Information Disclosure

For the year ended 31 March 2017

Pursuant to the Electricity Distribution Information Disclosure Determination 2012

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Company Name	**Aurora Energy Ltd**
For Year Ended	**31 March 2017**

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.
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

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

sch ref		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)
8						
9	**Operational expenditure**	21,393	315	94,280	4,478	31,213
10	Network	12,491	184	55,050	2,615	18,225
11	Non-network	8,901	131	39,230	1,863	12,987
12						
13	**Expenditure on assets**	23,469	346	103,429	4,912	34,242
14	Network	23,469	346	103,429	4,912	34,242
15	Non-network	–	–	–	–	–
16						

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

sch ref		Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
18			
19	**Total consumer line charge revenue**	72,362	1,067
20	Standard consumer line charge revenue	72,255	1,056
21	Non-standard consumer line charge revenue	84,119	51,416
22			

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

sch ref			
24			
25	Demand density	47	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
26	Volume density	209	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
27	Connection point density	14	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
28	Energy intensity	14,743	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*
29			

30 **1(iv): Composition of regulatory income**

sch ref		($000)	% of revenue
31			
32	Operational expenditure	27,472	28.59%
33	Pass-through and recoverable costs excluding financial incentives and wash-ups	37,270	38.78%
34	Total depreciation	12,836	13.36%
35	Total revaluations	7,381	7.68%
36	Regulatory tax allowance	5,990	6.23%
37	Regulatory profit/(loss) including financial incentives and wash-ups	19,917	20.72%
38	**Total regulatory income**	96,105	
39			

40 **1(v): Reliability**

sch ref			
41			
42	Interruption rate	13.99	*Interruptions per 100 circuit km*

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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

2(i): Return on Investment

	CY-2	CY-1	Current Year CY
	31 Mar 15	31 Mar 16	31 Mar 17
ROI – comparable to a post tax WACC	%	%	%
Reflecting all revenue earned	5.15%	4.99%	5.52%
Excluding revenue earned from financial incentives	5.15%	4.99%	5.52%
Excluding revenue earned from financial incentives and wash-ups	5.15%	4.99%	5.52%
Mid-point estimate of post tax WACC	6.10%	5.37%	4.77%
25th percentile estimate	5.39%	4.66%	4.05%
75th percentile estimate	6.82%	6.09%	5.48%
ROI – comparable to a vanilla WACC			
Reflecting all revenue earned	5.94%	5.63%	6.07%
Excluding revenue earned from financial incentives	5.94%	5.63%	6.07%
Excluding revenue earned from financial incentives and wash-ups	5.94%	5.63%	6.07%
WACC rate used to set regulatory price path	8.77%	7.19%	7.19%
Mid-point estimate of vanilla WACC	6.89%	6.02%	5.31%
25th percentile estimate	6.17%	5.30%	4.59%
75th percentile estimate	7.60%	6.74%	6.03%

2(ii): Information Supporting the ROI

			($000)	
	Total opening RAB value	340,665		
plus	Opening deferred tax	(16,402)		
Opening RIV			324,263	
Line charge revenue			92,637	
	Expenses cash outflow	64,742		
add	Assets commissioned	18,594		
less	Asset disposals	–		
add	Tax payments	3,495		
less	Other regulated income	3,468		
Mid-year net cash outflows			83,363	
Term credit spread differential allowance			–	
	Total closing RAB value	353,804		
less	Adjustment resulting from asset allocation	(0)		
less	Lost and found assets adjustment	–		
plus	Closing deferred tax	(18,897)		
Closing RIV			334,907	
ROI – comparable to a vanilla WACC				6.07%
	Leverage (%)			44%
	Cost of debt assumption (%)			4.41%
	Corporate tax rate (%)			28%
ROI – comparable to a post tax WACC				5.52%

2(iii): Information Supporting the Monthly ROI

Opening RIV N/A

	Line charge revenue	Expenses cash outflow	Assets commissioned	Asset disposals	Other regulated income	Monthly net cash outflows
April						–
May						–
June						–

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SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

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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							
70	July						–
71	August						–
72	September						–
73	October						–
74	November						–
75	December						–
76	January						–
77	February						–
78	March						–
79	**Total**	–	–	–	–	–	–
80							
81	**Tax payments**						N/A
82							
83	**Term credit spread differential allowance**						N/A
84							
85	**Closing RIV**						N/A
86							
87							
88	**Monthly ROI – comparable to a vanilla WACC**						N/A
89							
90	**Monthly ROI – comparable to a post tax WACC**						N/A
91							
92	**2(iv): Year-End ROI Rates for Comparison Purposes**						
93							
94	**Year-end ROI – comparable to a vanilla WACC**						5.97%
95							
96	**Year-end ROI – comparable to a post tax WACC**						5.43%
97							
98	** 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.*						
99							
100	**2(v): Financial Incentives and Wash-Ups**						
101							
102	Net recoverable costs allowed under incremental rolling incentive scheme					–	
103	Purchased assets – avoided transmission charge					–	
104	Energy efficiency and demand incentive allowance					–	
105	Quality incentive adjustment					–	
106	Other financial incentives					–	
107	**Financial incentives**						–
108							
109	**Impact of financial incentives on ROI**						–
110							
111	Input methodology claw-back						
112	Recoverable customised price-quality path costs					–	
113	Catastrophic event allowance					–	
114	Capex wash-up adjustment					–	
115	Transmission asset wash-up adjustment					–	
116	2013–2015 NPV wash-up allowance					–	
117	Reconsideration event allowance					–	
118	Other wash-ups					–	
119	**Wash-up costs**						–
120							
121	**Impact of wash-up costs on ROI**						–

Company Name	**Aurora Energy Ltd**
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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 all sections and provide explanatory comment on their regulatory profit 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

3(i): Regulatory Profit

		($000)
	Income	
	Line charge revenue	92,637
plus	Gains / (losses) on asset disposals	–
plus	Other regulated income (other than gains / (losses) on asset disposals)	3,468
	Total regulatory income	96,105
	Expenses	
less	Operational expenditure	27,472
less	Pass-through and recoverable costs excluding financial incentives and wash-ups	37,270
	Operating surplus / (deficit)	31,363
less	Total depreciation	12,836
plus	Total revaluations	7,381
	Regulatory profit / (loss) before tax	25,908
less	Term credit spread differential allowance	–
less	Regulatory tax allowance	5,990
	Regulatory profit/(loss) including financial incentives and wash-ups	19,917

3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups

	($000)	
Pass through costs		
Rates	926	
Commerce Act levies	140	
Industry levies	309	
CPP specified pass through costs	–	
Recoverable costs excluding financial incentives and wash-ups		
Electricity lines service charge payable to Transpower	26,584	
Transpower new investment contract charges	–	
System operator services	–	
Distributed generation allowance	7,987	
Extended reserves allowance	–	
Other recoverable costs excluding financial incentives and wash-ups	1,324	
Pass-through and recoverable costs excluding financial incentives and wash-ups		37,270

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SCHEDULE 3: REPORT ON REGULATORY PROFIT

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sch ref			
48	**3(iii): Incremental Rolling Incentive Scheme**	**($000)**	
49		**CY-1**	**CY**
50		**31 Mar 16**	**31 Mar 17**
51	Allowed controllable opex		
52	Actual controllable opex		
53			
54	Incremental change in year		
55			
56		**Previous years' incremental change**	**Previous years' incremental change adjusted for inflation**
57	CY-5 31 Mar 12		
58	CY-4 31 Mar 13		
59	CY-3 31 Mar 14		
60	CY-2 31 Mar 15		
61	CY-1 31 Mar 16		
62	**Net incremental rolling incentive scheme**		–
63			
64	**Net recoverable costs allowed under incremental rolling incentive scheme**		–
65	**3(iv): Merger and Acquisition Expenditure**		
70			**($000)**
66	Merger and acquisition expenditure		–
67			
68	*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)*		
69	**3(v): Other Disclosures**		
70			**($000)**
71	Self-insurance allowance		–

Company Name	**Aurora Energy Ltd**
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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

7 4(i): Regulatory Asset Base Value (Rolled Forward)

sch ref		RAB	RAB	RAB	RAB	RAB
8	for year ended	**31 Mar 13**	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**
9		**($000)**	**($000)**	**($000)**	**($000)**	**($000)**
10	**Total opening RAB value**	313,820	318,316	324,967	330,597	340,665
12	*less* **Total depreciation**	11,086	11,473	11,941	12,318	12,836
14	*plus* **Total revaluations**	2,696	4,879	273	1,940	7,381
16	*plus* **Assets commissioned**	12,886	13,374	17,298	20,446	18,594
18	*less* **Asset disposals**		129			–
20	*plus* **Lost and found assets adjustment**					–
22	*plus* **Adjustment resulting from asset allocation**					(0)
24	**Total closing RAB value**	318,316	324,967	330,597	340,665	353,804

26 4(ii): Unallocated Regulatory Asset Base

sch ref		Unallocated RAB *		RAB	
28		**($000)**	**($000)**	**($000)**	**($000)**
29	**Total opening RAB value**		340,665		340,665
30	*less*				
31	**Total depreciation**		12,836		12,836
32	*plus*				
33	**Total revaluations**		7,381		7,381
34	*plus*				
35	Assets commissioned (other than below)	7,085		7,085	
36	Assets acquired from a regulated supplier	–		–	
37	Assets acquired from a related party	11,509		11,509	
38	**Assets commissioned**		18,594		18,594
39	*less*				
40	Asset disposals (other than below)	–		–	
41	Asset disposals to a regulated supplier	–		–	
42	Asset disposals to a related party	–		–	
43	**Asset disposals**		–		–
45	*plus* **Lost and found assets adjustment**		–		–
47	*plus* **Adjustment resulting from asset allocation**				(0)
49	**Total closing RAB value**		353,804		353,804

** 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 services provided by the supplier that are not electricity distribution services. The RAB value represents the value of these assets after applying this cost allocation. Neither value includes works under construction.*

50

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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						
51						
52	**4(iii): Calculation of Revaluation Rate and Revaluation of Assets**					
53						
54		CPI_4				1,226
55		CPI_4^{-4}				1,200
56		Revaluation rate (%)				2.17%
57						
58			**Unallocated RAB ***		**RAB**	
59			**($000)**	**($000)**	**($000)**	**($000)**
60		Total opening RAB value	340,665		340,665	
61	*less*	Opening value of fully depreciated, disposed and lost assets	–		–	
62						
63		Total opening RAB value subject to revaluation	340,665		340,665	
64		**Total revaluations**		7,381		7,381
65						
66	**4(iv): Roll Forward of Works Under Construction**					
67			**Unallocated works under construction**		**Allocated works under construction**	
68		**Works under construction—preceding disclosure year**		17,972		17,972
69	*plus*	Capital expenditure	26,639		26,639	
70	*less*	Assets commissioned	18,594		18,594	
71	*plus*	Adjustment resulting from asset allocation				
72		**Works under construction - current disclosure year**		26,017		26,017
73						
74		Highest rate of capitalised finance applied				
75						

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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

76 4(v): Regulatory Depreciation

sch ref		Unallocated RAB *		RAB	
78		($000)	($000)	($000)	($000)
79	Depreciation - standard	12,836		12,836	
80	Depreciation - no standard life assets				
81	Depreciation - modified life assets				
82	Depreciation - alternative depreciation in accordance with CPP				
83	**Total depreciation**		12,836		12,836
84					

85 4(vi): Disclosure of Changes to Depreciation Profiles

($000 unless otherwise specified)

sch ref	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
87					
88					
89					
90					
91					
92					
93					
94					

95 ** include additional rows if needed*

96 4(vii): Disclosure by Asset Category

97 **($000 unless otherwise specified)**

sch ref			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
99		**Total opening RAB value**	13,414	9,082	64,021	52,400	125,626	51,795	20,091	4,236	–	340,665
100	*less*	Total depreciation	573	383	2,418	2,477	3,980	1,803	1,040	162		12,836
101	*plus*	Total revaluations	291	197	1,387	1,135	2,722	1,122	435	92		7,381
102	*plus*	Assets commissioned	2,006	2	751	5,395	2,519	1,075	1,026	5,820		18,594
103	*less*	Asset disposals										–
104	*plus*	Lost and found assets adjustment										–
105	*plus*	Adjustment resulting from asset allocation										–
106	*plus*	Asset category transfers										–
107		**Total closing RAB value**	15,138	8,898	63,741	56,453	126,887	52,189	20,512	9,986	–	353,804
108												
109		**Asset Life**										
110		Weighted average remaining asset life	23.4	23.7	25.3	21.2	31.6	28.7	19.3	21.6	–	(years)
111		Weighted average expected total asset life	49.2	63.8	41.0	51.2	57.6	45.0	36.0	15.0	–	(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					
7		**5a(i): Regulatory Tax Allowance**			**($000)**
8		**Regulatory profit / (loss) before tax**			25,908
9					
10	*plus*	Income not included in regulatory profit / (loss) before tax but taxable	2,918	*	
11		Expenditure or loss in regulatory profit / (loss) before tax but not deductible	154	*	
12		Amortisation of initial differences in asset values	4,993		
13		Amortisation of revaluations	961		
14					9,026
15					
16	*less*	Total revaluations	7,381		
17		Income included in regulatory profit / (loss) before tax but not taxable	–	*	
18		Discretionary discounts and customer rebates	–		
19		Expenditure or loss deductible but not in regulatory profit / (loss) before tax	–	*	
20		Notional deductible interest	6,158		
21					13,539
22					
23		**Regulatory taxable income**			21,395
24					
25	*less*	Utilised tax losses	–		
26		Regulatory net taxable income			21,395
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**			5,990
30					
31	*	Workings to be provided in Schedule 14			
32		**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).			
34		**5a(iii): Amortisation of Initial Difference in Asset Values**			**($000)**
35					
36		Opening unamortised initial differences in asset values	104,395		
37	*less*	Amortisation of initial differences in asset values	4,993		
38	*plus*	Adjustment for unamortised initial differences in assets acquired	–		
39	*less*	Adjustment for unamortised initial differences in assets disposed	–		
40		Closing unamortised initial differences in asset values			99,402
41					
42		Opening weighted average remaining useful life of relevant assets (years)			21
43					

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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				
44		**5a(iv): Amortisation of Revaluations**		**($000)**
45				
46		Opening sum of RAB values without revaluations	316,531	
47				
48		Adjusted depreciation	11,875	
49		Total depreciation	12,836	
50		Amortisation of revaluations		961
51				
52		**5a(v): Reconciliation of Tax Losses**		**($000)**
53				
54		**Opening tax losses**	–	
55	*plus*	Current period tax losses	–	
56	*less*	Utilised tax losses	–	
57		**Closing tax losses**		–
58		**5a(vi): Calculation of Deferred Tax Balance**		**($000)**
59				
60		**Opening deferred tax**	(16,402)	
61				
62	*plus*	Tax effect of adjusted depreciation	3,325	
63				
64	*less*	Tax effect of tax depreciation	5,196	
65				
66	*plus*	Tax effect of other temporary differences*	774	
67				
68	*less*	Tax effect of amortisation of initial differences in asset values	1,398	
69				
70	*plus*	Deferred tax balance relating to assets acquired in the disclosure year	–	
71				
72	*less*	Deferred tax balance relating to assets disposed in the disclosure year	–	
73				
74	*plus*	Deferred tax cost allocation adjustment	0	
75				
76		**Closing deferred tax**		(18,897)
77				
78		**5a(vii): Disclosure of Temporary Differences**		
79		*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 differences).*		
80				
81		**5a(viii): Regulatory Tax Asset Base Roll-Forward**		
82				**($000)**
83		**Opening sum of regulatory tax asset values**	195,107	
84	*less*	Tax depreciation	18,558	
85	*plus*	Regulatory tax asset value of assets commissioned	28,278	
86	*less*	Regulatory tax asset value of asset disposals	–	
87	*plus*	Lost and found assets adjustment	–	
88	*plus*	Adjustment resulting from asset allocation	–	
89	*plus*	Other adjustments to the RAB tax value	–	
90		**Closing sum of regulatory tax asset values**		204,827

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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

7 **5b(i): Summary—Related Party Transactions**

sch ref		($000)
8	Total regulatory income	207
9	Operational expenditure	24,923
10	Capital expenditure	11,509
11	Market value of asset disposals	
12	Other related party transactions	

13 **5b(ii): Entities Involved in Related Party Transactions**

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

20 ** include additional rows if needed*

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

sch ref	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	207	ID clause 2.3.7(2)(c)
24	Dunedin City Council	Opex	Rates Expense - Dunedin Disribution Network	804	ID clause 2.3.6(1)(c)(i)
25	Dunedin City Holdings Ltd	Opex	Management fee - recovery of share of costs running holding company	200	ID clause 2.3.6(1)(c)(i)
26	Delta Utility Services Ltd	Opex	Service Interruptions and Emergencies in accordance with Asset Management Agree ment and AMP	4,521	ID clause 2.3.6(1)(c)(i)
27	Delta Utility Services Ltd	Opex	Service Interruptions and Emergencies repair of equipment damaged by third parties	961	ID clause 2.3.6(1)(c)(i)
28	Delta Utility Services Ltd	Opex	On-going vegetation Management in accordance with Asset Management Agreement and AMP	3,699	ID clause 2.3.6(1)(c)(i)
29	Delta Utility Services Ltd	Opex	Routine inspection and maintenance work in accordance with Asset Management Agreement and AMP	6,430	ID clause 2.3.6(1)(c)(i)
30	Delta Utility Services Ltd	Opex	Asset Replacement and renewal work in accordance with Asset Management Agreement and AMP	279	ID clause 2.3.6(1)(c)(i)
31	Delta Utility Services Ltd	Opex	System Operation, support and management in accordance with Asset Management Agreement	3,867	ID clause 2.3.6(1)(c)(i)
	Delta Utility Services Ltd	Opex	Business support operations in accordance with Asset Management	3,255	ID clause 2.3.6(1)(c)(i)
32	Delta Utility Services Ltd	Opex	General management, administration and accounting services in accordance with Administration agreement	477	ID clause 2.3.6(1)(c)(i)
33	Delta Utility Services Ltd	Opex	Miscelanious work associated with processing of easements, minor offfice repairs adnd ad-hoc advise	350	ID clause 2.3.6(1)(c)(i)
34	Delta Utility Services Ltd	Opex	For lease of CPD metering equipment	85	ID clause 2.3.6(1)(c)(i)
35	Delta Utility Services Ltd	Capex	Design, installationa and project management of new network equipment	11,509	IM clause 2.2.11(5)(g)
36					
37					

38 ** include additional rows if needed*

Company Name	**Aurora Energy Ltd**
For Year Ended	**31 March 2017**

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

7

8 **5c(i): Qualifying Debt (may be Commission only)**

9

sch ref	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
11										
12										
13										
14										
15										
16	** include additional rows if needed*						–	–	–	–

17

18 **5c(ii): Attribution of Term Credit Spread Differential**

19

sch ref			
20	**Gross term credit spread differential**		–
21			
22	Total book value of interest bearing debt		
23	Leverage	44%	
24	Average opening and closing RAB values		
25	**Attribution Rate (%)**		–
26			
27	**Term credit spread differential allowance**		–

Company Name	**Aurora Energy Ltd**
For Year Ended	**31 March 2017**

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

sch ref	**5d(i): Operating Cost Allocations**					
8				**Value allocated ($000s)**		
9		**Arm's length deduction**	**Electricity distribution services**	**Non-electricity distribution services**	**Total**	**OVABAA allocation increase ($000s)**
10	**Service interruptions and emergencies**					
11	Directly attributable		5,633			
12	Not directly attributable				–	
13	**Total attributable to regulated service**		5,633			
14	**Vegetation management**					
15	Directly attributable		3,699			
16	Not directly attributable				–	
17	**Total attributable to regulated service**		3,699			
18	**Routine and corrective maintenance and inspection**					
19	Directly attributable		6,430			
20	Not directly attributable				–	
21	**Total attributable to regulated service**		6,430			
22	**Asset replacement and renewal**					
23	Directly attributable		279			
24	Not directly attributable				–	
25	**Total attributable to regulated service**		279			
26	**System operations and network support**					
27	Directly attributable		3,867			
28	Not directly attributable				–	
29	**Total attributable to regulated service**		3,867			
30	**Business support**					
31	Directly attributable		7,564			
32	Not directly attributable				–	
33	**Total attributable to regulated service**		7,564			
34						
35	**Operating costs directly attributable**		27,472			
36	**Operating costs not directly attributable**	–	–	–	–	–
37	**Operational expenditure**		27,472			
38						

Company Name	**Aurora Energy Ltd**
For Year Ended	**31 March 2017**

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

39 ### 5d(ii): Other Cost Allocations

sch ref		($000)
40	**Pass through and recoverable costs**	
41	**Pass through costs**	
42	Directly attributable	1,375
43	Not directly attributable	
44	**Total attributable to regulated service**	1,375
45	**Recoverable costs**	
46	Directly attributable	35,895
47	Not directly attributable	
48	**Total attributable to regulated service**	35,895
49		

50 ### 5d(iii): Changes in Cost Allocations* †

sch ref				($000) CY-1	($000) Current Year (CY)
51					
52	**Change in cost allocation 1**				
53	Cost category		Original allocation		
54	Original allocator or line items		New allocation		
55	New allocator or line items		Difference	–	–
56					
57	Rationale for change				
58					
59					
60					
61	**Change in cost allocation 2**				
62	Cost category		Original allocation		
63	Original allocator or line items		New allocation		
64	New allocator or line items		Difference	–	–
65					
66	Rationale for change				
67					
68					
69					
70	**Change in cost allocation 3**				
71	Cost category		Original allocation		
72	Original allocator or line items		New allocation		
73	New allocator or line items		Difference	–	–
74					
75	Rationale for change				
76					
77					

78 ** 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.*

79 *† include additional rows if needed*

Company Name	**Aurora Energy Ltd**
For Year Ended	**31 March 2017**

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	15,138
Not directly attributable	–
Total attributable to regulated service	15,138
Subtransmission cables	
Directly attributable	8,898
Not directly attributable	–
Total attributable to regulated service	8,898
Zone substations	
Directly attributable	63,741
Not directly attributable	–
Total attributable to regulated service	63,741
Distribution and LV lines	
Directly attributable	56,453
Not directly attributable	–
Total attributable to regulated service	56,453
Distribution and LV cables	
Directly attributable	126,887
Not directly attributable	–
Total attributable to regulated service	126,887
Distribution substations and transformers	
Directly attributable	52,189
Not directly attributable	–
Total attributable to regulated service	52,189
Distribution switchgear	
Directly attributable	20,512
Not directly attributable	
Total attributable to regulated service	20,512
Other network assets	
Directly attributable	9,986
Not directly attributable	
Total attributable to regulated service	9,986
Non-network assets	
Directly attributable	–
Not directly attributable	–
Total attributable to regulated service	–
Regulated service asset value directly attributable	353,804
Regulated service asset value not directly attributable	–
Total closing RAB value	353,804

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

			($000) CY-1	Current Year (CY)
Change in asset value allocation 1				
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	–	–
Rationale for change				

			($000) CY-1	Current Year (CY)
Change in asset value allocation 2				
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	–	–
Rationale for change				

			($000) CY-1	Current Year (CY)
Change in asset value allocation 3				
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 compone*
† include additional rows if needed

Company Name	**Aurora Energy Ltd**
For Year Ended	**31 March 2017**

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				
7		**6a(i): Expenditure on Assets**	**($000)**	**($000)**
8		Consumer connection		7,526
9		System growth		270
10		Asset replacement and renewal		18,128
11		Asset relocations		2,081
12		Reliability, safety and environment:		
13		Quality of supply	1,310	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	823	
16		**Total reliability, safety and environment**		2,133
17		**Expenditure on network assets**		30,138
18		Expenditure on non-network assets		–
19				
20		**Expenditure on assets**		30,138
21	*plus*	Cost of financing		–
22	*less*	Value of capital contributions		3,499
23	*plus*	Value of vested assets		–
24				
25		**Capital expenditure**		26,639
26		**6a(ii): Subcomponents of Expenditure on Assets (where known)**		**($000)**
27		Energy efficiency and demand side management, reduction of energy losses		
28		Overhead to underground conversion		
29		Research and development		
30		**6a(iii): Consumer Connection**		
31		*Consumer types defined by EDB**	**($000)**	**($000)**
32		[EDB consumer type]	7,526	
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**		7,526
39				
40	*less*	Capital contributions funding consumer connection expenditure	2,904	
41		**Consumer connection less capital contributions**		4,622
42		**6a(iv): System Growth and Asset Replacement and Renewal**		**Asset Replacement and**
43			**System Growth**	**Renewal**
44			**($000)**	**($000)**
45		Subtransmission	4	2,622
46		Zone substations	23	855
47		Distribution and LV lines	82	5,109
48		Distribution and LV cables	106	883
49		Distribution substations and transformers	–	398
50		Distribution switchgear	3	856
51		Other network assets	52	7,405
52		**System growth and asset replacement and renewal expenditure**	270	18,128
53	*less*	Capital contributions funding system growth and asset replacement and renewal	27	26
54		**System growth and asset replacement and renewal less capital contributions**	243	18,102
55				
56		**6a(v): Asset Relocations**		
57		*Project or programme**	**($000)**	**($000)**
58		CFR 7958, Five Mile Asset Relocation Enabling Works	400	
59		Taras	218	
60		CFR 8462 Chorus Changeover Project 2016/17	217	
61		CFR 7961 Aurora asset changeover from Telecom Poles	186	
62		CFR 8099n Rydges Hotel - Brunswick Street	108	
63		** include additional rows if needed*		
64		All other projects or programmes - asset relocations	952	
65		**Asset relocations expenditure**		2,081
66	*less*	Capital contributions funding asset relocations	493	
67		**Asset relocations less capital contributions**		1,588

Company Name	**Aurora Energy Ltd**	
For Year Ended	**31 March 2017**	

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)
68				
69	**6a(vi): Quality of Supply**			
70		*Project or programme**	**($000)**	**($000)**
71		CFR 6719, Upgrade Alexandra Ripple Plant	149	
72		CFR 7984, Voltage Complaint No 15002, Bideford St Dunedin	140	
73		CFR 8367, Voltage Regulator Procurement	107	
74		CFR 8117, Central Load Control Scada and installing of communication links	102	
75		CFR 8042, Instalation of anti pimping relays at 3 zone substations3	81	
76		** include additional rows if needed*		
77		All other projects programmes - quality of supply	731	
78	**Quality of supply expenditure**			1,310
79	*less*	Capital contributions funding quality of supply	32	
80	**Quality of supply less capital contributions**			1,278
81	**6a(vii): Legislative and Regulatory**			
82		*Project or programme**	**($000)**	**($000)**
83		[Description of material project or programme]		
84		[Description of material project or programme]		
85		[Description of material project or programme]		
86		[Description of material project or programme]		
87		[Description of material project or programme]		
88		** include additional rows if needed*		
89		All other projects or programmes - legislative and regulatory		
90	**Legislative and regulatory expenditure**			–
91	*less*	Capital contributions funding legislative and regulatory		
92	**Legislative and regulatory less capital contributions**			–
93	**6a(viii): Other Reliability, Safety and Environment**			
94		*Project or programme**	**($000)**	**($000)**
95		CFR 8025, Replacement pogram Cast iron pot heads	161	
96		CFR 8440, replace Distribution Transformer following structure test failure	69	
97		CFR 8032, Design of remote alarm system for underground substations	66	
98		CFR 7754, Sagging LV conductors	45	
99		CFR 7920, LV OH clearance issues - Portobello Road	44	
100		** include additional rows if needed*		
101		All other projects or programmes - other reliability, safety and environment	438	
102	**Other reliability, safety and environment expenditure**			823
103	*less*	Capital contributions funding other reliability, safety and environment	17	
104	**Other reliability, safety and environment less capital contributions**			806
105				
106	**6a(ix): Non-Network Assets**			
107	**Routine expenditure**			
108		*Project or programme**	**($000)**	**($000)**
109		[Description of material project or programme]		
110		[Description of material project or programme]		
111		[Description of material project or programme]		
112		[Description of material project or programme]		
113		[Description of material project or programme]		
114		** include additional rows if needed*		
115		All other projects or programmes - routine expenditure		
116	**Routine expenditure**			–
117	**Atypical expenditure**			
118		*Project or programme**	**($000)**	**($000)**
119		[Description of material project or programme]		
120		[Description of material project or programme]		
121		[Description of material project or programme]		
122		[Description of material project or programme]		
123		[Description of material project or programme]		
124		** include additional rows if needed*		
125		All other projects or programmes - atypical expenditure		
126	**Atypical expenditure**			–
127				
128	**Expenditure on non-network assets**			–

Company Name	**Aurora Energy Ltd**
For Year Ended	**31 March 2017**

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

This schedule requires a breakdown of operational 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 operational 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			
7	**6b(i): Operational Expenditure**	**($000)**	**($000)**
8	Service interruptions and emergencies	5,633	
9	Vegetation management	3,699	
10	Routine and corrective maintenance and inspection	6,430	
11	Asset replacement and renewal	279	
12	**Network opex**		16,041
13	System operations and network support	3,867	
14	Business support	7,564	
15	**Non-network opex**		11,431
16			
17	**Operational expenditure**		27,472
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		195
23	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**Aurora Energy Ltd**
For Year Ended	**31 March 2017**

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	91,020	92,640	2%
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	8,671	7,526	(13%)
11	System growth	1,124	270	(76%)
12	Asset replacement and renewal	8,393	18,128	116%
13	Asset relocations	1,775	2,081	17%
14	Reliability, safety and environment:			
15	Quality of supply	1,140	1,310	15%
16	Legislative and regulatory		–	–
17	Other reliability, safety and environment	728	823	13%
18	**Total reliability, safety and environment**	1,868	2,133	14%
19	**Expenditure on network assets**	21,831	30,138	38%
20	Expenditure on non-network assets		–	–
21	Expenditure on assets	21,831	30,138	38%
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	3,267	5,633	72%
24	Vegetation management	4,616	3,699	(20%)
25	Routine and corrective maintenance and inspection	6,540	6,430	(2%)
26	Asset replacement and renewal	424	279	(34%)
27	**Network opex**	14,848	16,041	8%
28	System operations and network support	3,555	3,867	9%
29	Business support	2,962	7,564	155%
30	**Non-network opex**	6,517	11,431	75%
31	**Operational expenditure**	21,364	27,472	29%
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		–	–
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		195	–
42				

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

44 *2 From the CY+1 nominal dollar expenditure forecasts disclosed in accordance with clause 2.6.6 for the forecast period starting at the beginning of the disclosure year (the second to last disclosure of Schedules 11a and 11b)*

Company Name	Aurora Energy Ltd
For Year Ended	31 March 2017
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

11 Billed quantities by price component

sch ref	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 (Pass-through)	Energy Delivery (Pass-through)	Capacity (Pass-through)	Control Period Demand (Pass-through)
13					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
15	Residential	Residential	Standard	72,923	576,410	26,616,958		576,409,820						575,789,723		
16	Load Group 0	General	Standard	320	36	116,839							116,839			
17	Load Group 0A	General	Standard	640	1,075	233,644							45,072			
18	Load Group 1A	General	Standard	831	2,607	303,316			2,426,528		294,787				2,423,608	294,422
19	Load Group 1	General	Standard	5,674	44,741	2,071,127			31,066,905		4,917,462				31,066,905	4,917,462
20	Load Group 2	General	Standard	6,169	273,314	2,251,776			113,008,947		16,459,675	(520)			112,985,222	16,457,485
21	Load Group 2	General	Non-standard	3	110	1,095			73,480						73,480	
22	Load Group 3	General	Standard	214	56,825	77,957			14,941,874	242,626,093	3,328,191	(280)			14,941,874	3,328,191
23	Load Group 3	General	Non-standard	2	522	730			133,600	1,726,780		(280)			133,600	
24A	Load Group 3A	General	Standard	167	84,367	60,801			18,473,795	240,822,483	4,900,055	(295)			18,473,795	4,900,055
24B	Load Group 3A	General	Non-standard	2	1,440	730			292,000	7,099,980		(280)			292,000	
24C	Load Group 4	General	Standard	124	162,075	45,225			32,388,514	416,709,800	9,047,728	76,497			32,388,514	9,047,728
24D	Load Group 4	General	Non-standard	1	4,128	365							365			
24E	Load Group 5	General	Standard	8	60,843	2,920			9,953,497	114,035,514	2,680,925	8,167			9,953,497	2,680,925
24F	Load Group 5	General	Non-standard	1	5,413	365							365			
24G	Street Lighting	General	Standard	11	10,261	730	2,432,444	2,929,060					730	2,902,053		
24H	DUML, excl Street Lighting	General	Standard	2	3	730		2,773						2,773		
24I	Distributed Generation (Large)	General	Non-standard	10	N/A	10		N/A					–	N/A		
25	*Add extra rows for additional consumer groups or price category codes as necessary*															
26			Standard consumer totals	87,083	1,272,557	31,782,023	2,432,444	579,341,653	222,260,060	1,014,193,890	41,628,823	83,569	162,641	578,694,549	222,233,415	41,626,268
27			Non-standard consumer totals	19	11,613	3,295	–	–	499,080	8,826,760	–	(560)	730	–	499,080	–
28			Total for all consumers	87,102	1,284,170	31,785,318	2,432,444	579,341,653	222,759,140	1,023,020,650	41,628,823	83,009	163,371	578,694,549	222,732,495	41,626,268

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

31 ### 8(ii): Line Charge Revenues ($000) by Price Component

33 Line charge revenues ($000) by price component

sch ref	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 from posted discounts (if applicable)	Total distribution line charge revenue	Total pass-through 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 (Pass-through)	Energy Delivery (Pass-through)	Capacity (Pass-through)	Control Period Demand (Pass-through)
35							Rate (eg, $ per day, $ per kWh, etc.)	$ / annum	$ / lamp	$ / kWh	$ / kVA	$ / kVA x km	$ / kW	$ / kVA	$ / annum	$ / kWh	$ / kVA	$ / kW
37	Residential	Residential	Standard	$52,947		$34,260	$18,687	$3,964		$30,296						$18,687		
38	Load Group 0	General	Standard	$73		$46	$26	$46							$26			
39	Load Group 0A	General	Standard	$310		$191	$119	$191							$119			
40	Load Group 1A	General	Standard	$381		$231	$150	$10			$131		$91				$61	$88
41	Load Group 1	General	Standard	$5,166		$2,995	$2,171	$66			$1,494		$1,436				$689	$1,481
42	Load Group 2	General	Standard	$16,042		$10,492	$5,550	$144			$5,738		$4,616	-$6			$834	$4,716
43	Load Group 2	General	Non-standard	$5		$5	$0	$0			$5		$0				$0	$0
44	Load Group 3	General	Standard	$3,328		$2,260	$1,067	$98			$1,196	$232	$735	$0			$193	$874
45	Load Group 3	General	Non-standard	$10		$10	$0	$1			$10	$2		-$3			$0	
46A	Load Group 3A	General	Standard	$4,217		$2,662	$1,555	$75			$1,372	$226	$993	-$4			$271	$1,284
46B	Load Group 3A	General	Non-standard	$26		$25	$1	$1			$20	$7		-$3			$1	
46C	Load Group 4	General	Standard	$7,266		$4,200	$3,066	$139			$1,417	$391	$1,616	$637			$708	$2,358
46D	Load Group 4	General	Non-standard	$135		$71	$64	$71							$64			
46E	Load Group 5	General	Standard	$1,561		$680	$881	$9			$259	$103	$237	$73			$134	$747
46F	Load Group 5	General	Non-standard	$219		$84	$135	$84							$135			
46G	Street Lighting	General	Standard	$658		$452	$205	$278	$90	$84					$149	$56		
46H	DUML, excl Street Lighting	General	Standard	$0		$0	$0	$0		$0						$0		
46I	Distributed Generation (Large)	General	Non-standard	$582		$582		$582										
47	*Add extra rows for additional consumer groups or price category codes as necessary*																	
48			Standard consumer totals	$91,949	–	$58,472	$33,477	$5,019	$90	$30,380	$11,607	$951	$9,724	$700	$294	$18,744	$2,890	$11,549
49			Non-standard consumer totals	$977	–	$777	$200	$739	–	–	$35	$9	$0	($6)	$199	–	$1	$0
50			Total for all consumers	$92,926	–	$59,249	$33,677	$5,758	$90	$30,380	$11,642	$960	$9,724	$693	$493	$18,744	$2,891	$11,549

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

52 ### 8(iii): Number of ICPs directly billed

Check: OK

53 Number of directly billed ICPs at year end: 19

Company Name	**Aurora Energy Ltd**
For Year Ended	**31 March 2017**
Network / Sub-Network Name	**Dunedin Sub-network**

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

sch ref	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)
15	Residential	Residential	Standard	47,716	380,145
16	Load Group 0	General	Standard	109	5
17	Load Group 0A	General	Standard	123	111
18	Load Group 1A	General	Standard	399	1,208
19	Load Group 1	General	Standard	3,005	23,220
20	Load Group 2	General	Standard	3,053	138,972
21	Load Group 2	General	Non-standard	–	–
22	Load Group 3	General	Standard	107	32,955
23	Load Group 3	General	Non-standard	–	–
24A	Load Group 3A	General	Standard	91	51,748
24B	Load Group 3A	General	Non-standard	–	–
24C	Load Group 4	General	Standard	73	106,294
24D	Load Group 4	General	Non-standard	–	–
24E	Load Group 5	General	Standard	7	54,215
24F	Load Group 5	General	Non-standard	–	–
24G	Street Lighting	General	Standard	2	7,332
24H	DUML, excl Street Lighting	General	Standard	2	3
24I	Distributed Generation (Large)	General	Non-standard	1	N/A
25	*Add extra rows for additional consumer groups or price category codes as necessary*				
26			**Standard consumer totals**	54,687	796,206
27			**Non-standard consumer totals**	1	–
28			**Total for all consumers**	54,688	796,206

Billed quantities by price component

sch ref	Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Perod Demand (Distribution)	Transformer Lease. Other Charges & Rebates (Distribution)	Fixed (Pass-through)	Energy Delivery (Pass-through)	Capacity (Pass-through)	Control Period Demand (Pass-through)
13 **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
15	17,416,262		380,144,551						380,144,551		
16	39,758							39,758			
17	45,072							45,072			
18	145,722			1,165,776		135,677				1,165,776	135,677
19	1,096,742			16,451,130		2,619,511				16,451,130	2,619,511
20	1,114,454			56,405,541		8,763,059	(5)			56,405,541	8,763,059
21	–									–	–
22	39,178			7,723,969	42,636,768	2,124,206				7,723,969	2,124,206
23	–									–	–
24A	33,033			10,253,921	55,832,577	3,242,099	(295)			10,253,921	3,242,099
24B	–									–	–
24C	26,494			20,037,037	108,793,110	5,903,134	47,722			20,037,037	5,903,134
24D	–										
24E	2,555			9,040,997	53,901,764	2,665,230	8,167			9,040,997	2,665,230
24F	–										
24G	730							730			
24H	730		2,773						2,773		
24I	1		N/A						N/A		
26	19,960,730	–	380,147,324	121,078,371	261,164,219	25,452,916	55,589	85,560	380,147,324	121,078,371	25,452,916
27	1	–	–	–	–	–	–	–	–	–	–
28	19,960,731	–	380,147,324	121,078,371	261,164,219	25,452,916	55,589	85,560	380,147,324	121,078,371	25,452,916

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

31 8(ii): Line Charge Revenues ($000) by Price Component

sch ref	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 from posted discounts (if applicable)	Total distribution line charge revenue	Total pass-through line charge revenue (if available)
37	Residential	Residential	Standard	$28,968		$17,063	$11,905
38	Load Group 0	General	Standard	$23		$12	$10
39	Load Group 0A	General	Standard	$54		$29	$25
40	Load Group 1A	General	Standard	$161		$85	$76
41	Load Group 1	General	Standard	$2,510		$1,284	$1,226
42	Load Group 2	General	Standard	$7,885		$4,789	$3,097
43	Load Group 2	General	Non-standard	–			
44	Load Group 3	General	Standard	$1,710		$994	$716
45	Load Group 3	General	Non-standard	–			
46A	Load Group 3A	General	Standard	$2,372		$1,304	$1,068
46B	Load Group 3A	General	Non-standard	–			
46C	Load Group 4	General	Standard	$4,230		$2,143	$2,087
46D	Load Group 4	General	Non-standard	–			
46E	Load Group 5	General	Standard	$1,443		$567	$875
46F	Load Group 5	General	Non-standard	–			
46G	Street Lighting	General	Standard	$427		$278	$149
46H	DUML, excl Street Lighting	General	Standard	$0		$0	$0
46I	Distributed Generation (Large)	General	Non-standard	$123		$123	
47	*Add extra rows for additional consumer groups or price category codes as necessary*						
48			**Standard consumer totals**	$49,783	–	$28,548	$21,235
49			**Non-standard consumer totals**	$123	–	$123	–
50			**Total for all consumers**	$49,906	–	$28,671	$21,235

Line charge revenues ($000) by price component

sch ref	Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Perod Demand (Distribution)	Transformer Lease. Other Charges & Rebates (Distribution)	Fixed (Pass-through)	Energy Delivery (Pass-through)	Capacity (Pass-through)	Control Period Demand (Pass-through)
35 **Rate (eg, $ per day, $ per kWh, etc.)**	$ / annum	$ / lamp	$ / kWh	$ / kVA	$ / kVA x km	$ / kW	$ / kVA	$ / annum	$ / kWh	$ / kVA	$ / kW
37	$2,591		$14,472						$11,905		
38	$12							$10			
39	$29							$25			
40	$4			$47		$34				$34	$42
41	$32			$594		$659				$415	$811
42	$70			$2,516		$2,203	$0			$384	$2,713
43											
44	$45			$564	$34	$351				$124	$592
45											
46A	$38			$689	$45	$536	-$4			$164	$904
46B											
46C	$76			$737	$87	$847	$395			$441	$1,646
46D											
46E	$7			$213	$43	$231	$73			$132	$743
46F											
46G	$278							$149			
46H	$0		$0						$0		
46I	$123										
48	$3,182	–	$14,472	$5,360	$209	$4,861	$464	$184	$11,906	$1,693	$7,452
49	$123	–	–	–	–	–	–	–	–	–	–
50	$3,305	–	$14,472	$5,360	$209	$4,861	$464	$184	$11,906	$1,693	$7,452

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

52 8(iii): Number of ICPs directly billed

Check OK

53 **Number of directly billed ICPs at year end** 1

Company Name	Aurora Energy Ltd
For Year Ended	31 March 2017
Network / Sub-Network Name	Central Otago Sub-network

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**

sch ref	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)
15	Residential	Residential	Standard	25,110	195,645
16	Load Group 0	General	Standard	211	31
17	Load Group 0A	General	Standard	513	959
18	Load Group 1A	General	Standard	431	1,396
19	Load Group 1	General	Standard	2,670	21,521
20	Load Group 2	General	Standard	3,114	134,319
21	Load Group 2	General	Non-standard	3	110
22	Load Group 3	General	Standard	106	23,870
23	Load Group 3	General	Non-standard	2	522
24A	Load Group 3A	General	Standard	76	32,619
24B	Load Group 3A	General	Non-standard	2	1,440
24C	Load Group 4	General	Standard	51	55,781
24D	Load Group 4	General	Non-standard	1	4,128
24E	Load Group 5	General	Standard	1	6,628
24F	Load Group 5	General	Non-standard	1	5,413
24G	Street Lighting	General	Standard	8	2,902
24H	DUML, excl Street Lighting	General	Standard	–	
24I	Distributed Generation (Large)	General	Non-standard	9	N/A
25	*Add extra rows for additional consumer groups or price category codes as necessary*				
26			**Standard consumer totals**	32,291	475,671
27			**Non-standard consumer totals**	9	11,613
28			**Total for all consumers**	32,300	487,284

Billed quantities by price component

sch ref	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 (Pass-through)	Energy Delivery (Pass-through)	Capacity (Pass-through)	Control Period Demand (Pass-through)
13	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
15	Residential	9,165,239		195,645,172						195,645,172		
16	Load Group 0	77,081							77,081			
17	Load Group 0A	187,201										
18	Load Group 1A	157,229			1,257,832		158,745				1,257,832	158,745
19	Load Group 1	974,385			14,615,775		2,297,951				14,615,775	2,297,951
20	Load Group 2	1,136,592			56,579,681		7,694,426	(515)			56,579,681	7,694,426
21	Load Group 2	1,095			73,480		–				73,480	–
22	Load Group 3	38,779			7,217,905	199,989,325	1,203,985	(280)			7,217,905	1,203,985
23	Load Group 3	730			133,600	1,726,780	–	(280)			133,600	–
24A	Load Group 3A	27,768			8,219,874	184,989,906	1,657,956				8,219,874	1,657,956
24B	Load Group 3A	730			292,000	7,099,980	–	(280)			292,000	–
24C	Load Group 4	18,731			12,351,477	307,916,690	3,144,594	28,775			12,351,477	3,144,594
24D	Load Group 4	365					–		365			
24E	Load Group 5	365			912,500	60,133,750	15,695				912,500	15,695
24F	Load Group 5	365			–	–	–		365			
24G	Street Lighting		2,402,879	2,902,053						2,902,053		
24H	DUML, excl Street Lighting											
24I	Distributed Generation (Large)	9		N/A								
26	Standard consumer totals	11,783,370	2,402,879	198,547,225	101,155,044	753,029,671	16,173,352	27,980	77,081	198,547,225	101,155,044	16,173,352
27	Non-standard consumer totals	3,285	–	–	499,080	8,826,760	–	(560)	730	–	499,080	–
28	Total for all consumers	11,786,655	2,402,879	198,547,225	101,654,124	761,856,431	16,173,352	27,420	77,811	198,547,225	101,654,124	16,173,352

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

31 **8(ii): Line Charge Revenues ($000) by Price Component**

sch ref	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 from posted discounts (if applicable)	Total distribution line charge revenue	Total pass-through line charge revenue (if available)
37	Residential	Residential	Standard	$23,905		$17,123	$6,782
38	Load Group 0	General	Standard	$50		$34	$16
39	Load Group 0A	General	Standard	$255		$160	$94
40	Load Group 1A	General	Standard	$219		$146	$74
41	Load Group 1	General	Standard	$2,656		$1,711	$945
42	Load Group 2	General	Standard	$8,154		$5,701	$2,453
43	Load Group 2	General	Non-standard	$5		$5	$0
44	Load Group 3	General	Standard	$1,618		$1,266	$351
45	Load Group 3	General	Non-standard	$10		$10	$0
46A	Load Group 3A	General	Standard	$1,844		$1,358	$487
46B	Load Group 3A	General	Non-standard	$26		$25	$1
46C	Load Group 4	General	Standard	$3,036		$2,058	$978
46D	Load Group 4	General	Non-standard	$135		$71	$64
46E	Load Group 5	General	Standard	$119		$113	$6
46F	Load Group 5	General	Non-standard	$219		$84	$135
46G	Street Lighting	General	Standard	$228		$172	$56
46H	DUML, excl Street Lighting	General	Standard	–			
46I	Distributed Generation (Large)	General	Non-standard	$459		$459	
47	*Add extra rows for additional consumer groups or price category codes as necessary*						
48			**Standard consumer totals**	$42,084	–	$29,842	$12,242
49			**Non-standard consumer totals**	$854	–	$654	$200
50			**Total for all consumers**	$42,938	–	$30,496	$12,442

Line charge revenues ($000) by price component

sch ref	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 (Pass-through)	Energy Delivery (Pass-through)	Capacity (Pass-through)	Control Period Demand (Pass-through)
35	Rate (eg, $ per day, $ per kWh, etc.)	$ / annum	$ / lamp	$ / kWh	$ / kVA	$ / kVA x km	$ / kW	$ / kVA	$ / annum	$ / kWh	$ / kVA	$ / kW
37	Residential	$1,368		$15,755						$6,782		
38	Load Group 0	$34							$16			
39	Load Group 0A	$160							$94			
40	Load Group 1A	$5			$84		$57				$27	$46
41	Load Group 1	$34			$900		$777				$275	$670
42	Load Group 2	$74			$3,221		$2,412	-$6			$450	$2,003
43	Load Group 2	$0			$5		$0				$0	$0
44	Load Group 3	$53			$632	$198	$384	$0			$70	$281
45	Load Group 3	$1			$10	$2		-$3			$0	
46A	Load Group 3A	$37			$683	$181	$457				$107	$380
46B	Load Group 3A	$1			$20	$7		-$3			$1	
46C	Load Group 4	$63			$680	$304	$769	$242			$267	$711
46D	Load Group 4	$71							$64			
46E	Load Group 5	$1			$45	$60	$6				$2	$4
46F	Load Group 5	$84							$135			
46G	Street Lighting		$89	$82						$56		
46H	DUML, excl Street Lighting											
46I	Distributed Generation (Large)	$459										
48	Standard consumer totals	$1,830	$89	$15,838	$6,245	$742	$4,861	$236	$110	$6,838	$1,198	$4,096
49	Non-standard consumer totals	$616	–	–	$35	$9	$0	($6)	$199	–	$1	$0
50	Total for all consumers	$2,446	$89	$15,838	$6,281	$751	$4,861	$229	$309	$6,838	$1,199	$4,096

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

52 **8(iii): Number of ICPs directly billed**

Check: OK

53 **Number of directly billed ICPs at year end**: 18

Company Name	**Aurora Energy Ltd**
For Year Ended	**31 March 2017**
Network / Sub-network Name	**Total Network**

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.	21,775	23,132	1,357	4
10	All	Overhead Line	Wood poles	No.	32,349	30,820	(1,529)	4
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	526	526	–	3
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	20	21	1	3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	25	25	–	3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	36	36	–	3
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	11	11	–	3
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	N/A
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	N/A
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	30	30	–	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	N/A
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	5	5	–	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	236	240	4	3
29	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	6	6	–	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	53	53	–	3
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	349	348	(1)	3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	15	15	–	3
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	67	67	–	3
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2,308	2,306	(2)	3
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	9	9	–	3
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	564	586	22	3
39	HV	Distribution Cable	Distribution UG PILC	km	429	428	(1)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	1	1	–	3
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	40	44	4	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	9	5	(4)	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	6,425	6,473	48	3
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	975	981	6	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	545	582	37	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	4,155	4,134	(21)	3
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	2,759	2,811	52	3
48	HV	Distribution Transformer	Voltage regulators	No.	39	41	2	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	2,670	2,811	141	3
50	LV	LV Line	LV OH Conductor	km	1,050	1,047	(3)	3
51	LV	LV Cable	LV UG Cable	km	877	926	49	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	221	221	–	3
53	LV	Connections	OH/UG consumer service connections	No.	86,870	88,305	1,435	3
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	475	476	1	3
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	97	109	12	3
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	2,206	2,209	3	3
59	All	Civils	Cable Tunnels	km	–		–	N/A

Company Name	**Aurora Energy Ltd**
For Year Ended	**31 March 2017**
Network / Sub-network Name	**Dunedin Sub-network**

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

	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
8								
9	All	Overhead Line	Concrete poles / steel structure	No.	14,881	15,327	446	4
10	All	Overhead Line	Wood poles	No.	14,542	14,018	(524)	4
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	144	144	–	3
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	4	4	–	3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	25	25	–	3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	36	36	–	3
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	11	11	–	3
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	N/A
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	N/A
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	18	18	–	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	N/A
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	111	111	–	3
29	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	23	23	–	3
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	262	262	–	3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	3
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	35	35	–	3
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	731	731	–	3
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	9	9	–	3
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	31	34	3	3
39	HV	Distribution Cable	Distribution UG PILC	km	280	280	–	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	1	1	–	3
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	10	13	3	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	6	5	(1)	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	2,563	2,584	21	3
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	460	451	(9)	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	318	323	5	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	1,706	1,702	(4)	3
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	917	930	13	3
48	HV	Distribution Transformer	Voltage regulators	No.	11	12	1	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	917	930	13	3
50	LV	LV Line	LV OH Conductor	km	824	822	(2)	3
51	LV	LV Cable	LV UG Cable	km	257	265	8	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	154	154	–	3
53	LV	Connections	OH/UG consumer service connections	No.	54,912	55,259	347	3
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	301	303	2	3
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	39	45	6	3
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	1,121	1,112	(9)	3
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

Company Name	**Aurora Energy Ltd**
For Year Ended	**31 March 2017**
Network / Sub-network Name	**Central Otago Sub-network**

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

	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
8								
9	All	Overhead Line	Concrete poles / steel structure	No.	7,409	7,805	396	4
10	All	Overhead Line	Wood poles	No.	17,215	16,802	(413)	4
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	382	382	–	3
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	17	17	–	3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–		–	3
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	3
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	N/A
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	N/A
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	12	12	–	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	N/A
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	5	5	–	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	127	129	2	3
29	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	6	6	–	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	30	30	–	3
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	89	86	(3)	3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	15	15	–	3
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	32	32	–	3
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1,576	1,576	–	3
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	–	–	–	3
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	531	551	20	3
39	HV	Distribution Cable	Distribution UG PILC	km	148	147	(1)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	3
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	27	31	4	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.	3,919	3,889	(30)	3
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	523	529	6	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	253	258	5	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	2,446	2,432	(14)	3
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	1,837	1,876	39	3
48	HV	Distribution Transformer	Voltage regulators	No.	30	29	(1)	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	1,837	1,876	39	3
50	LV	LV Line	LV OH Conductor	km	225	225	–	3
51	LV	LV Cable	LV UG Cable	km	639	656	17	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	71	71	–	3
53	LV	Connections	OH/UG consumer service connections	No.	31,876	32,943	1,067	3
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	174	173	(1)	3
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	59	64	5	3
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	1,086	1,092	6	3
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

Company Name	**Aurora Energy Ltd**
For Year Ended	**31 March 2017**
Network / Sub-network Name	**Total Network**

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

8 **Disclosure Year (year ended)** 31 March 2017

Number of assets at disclosure year end by installation date

sch ref	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001
10	All	Overhead Line	Concrete poles / steel structure	No.	–	25	1,722	6,433	4,742	3,178	1,828	88	98
11	All	Overhead Line	Wood poles	No.	1,157	1,368	2,421	8,445	5,703	3,852	3,370	326	230
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	71	3	73	107	75	38	128	–	–
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	–	1	7	–	–
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	–	22	3	–	–	–
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	6	27	2	1	–	–	–
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	9	–	–	–	1	–	–
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	–	–	–	–	–	–
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	–	–	–	–	–	–
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	–	–	–	–	–	–
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	–	–	–	–	–	–
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	–	–	–	–	–	–
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.		1	5	3	7	5	4	–	–
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	–	–	–	–
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	–	–	–	–
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	51	25	7	27	24	–	–
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	6	–	–
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	3	4	5	4	8	7	–	–
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	32	46	37	80	9	26	–	–
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	4	2	1	–	–	–	–
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	11	11	18	6	4	–	–
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	77	136	321	424	416	383	339	11	10
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km									
38	HV	Distribution Line	SWER conductor	km	–	–	6	2	–	1	–	–	–
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	–	–	–	5	13	73	22	22
40	HV	Distribution Cable	Distribution UG PILC	km	–	8	36	54	68	77	69	8	8
41	HV	Distribution Cable	Distribution Submarine Cable	km	–	1	–	–	–	–	–	–	–
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	–	–	–	–	–	–	2	–	–
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	1	–	1	–	–
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1	28	108	729	662	868	1,329	152	160
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	1	–	10	104	68	79	177	29	25
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	1	45	87	131	13	17
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	61	76	319	847	569	525	757	48	51
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	31	167	284	178	327	73	107
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	6	3	4	1	–	–
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	31	167	284	178	327	73	107
51	LV	LV Line	LV OH Conductor	km	56	42	109	263	211	172	154	5	2
52	LV	LV Cable	LV UG Cable	km	–	–	2	26	43	173	156	21	23
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	5	3	4	10	10	27	97	2	1
54	LV	Connections	OH/UG consumer service connections	No.	12,847	3,657	6,909	8,623	6,957	4,488	22,419	990	1,162
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	35	54	44	86	17	42	–	–
56	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	–	–	–	–	–	3	–	–	4
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	–	–	–
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	–	–	–	–
59	All	Load Control	Relays	No	–	1	3	51	79	127	268	39	40
60	All	Civils	Cable Tunnels	km									

sch ref	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	No. with age unknown	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
10	198	129	78	114	184	172	212	105	153	230	587	474	680	664	636	402	–	23,132		4
11	385	446	315	265	327	289	321	327	342	344	151	101	104	90	75	66	–	30,820		4
12	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
13	–	–	–	–	6	–	–	4	4	12	–	–	3	2	–	–	–	526		3
14	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
15	–	–	1	1	–	1	2	1	–	1	1	–	4	–	1	–	–	21		3
16	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	25		3
17	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	36		3
18	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	11		3
19	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
20	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
21	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
22	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
23	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
24	–	–	–	–	–	–	–	1	–	1	–	1	–	2	–	–	–	30		4
25	–	–	–	–	–	–	–	0	–	–	–	–	–	–	–	–	–	–		N/A
26	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
27	–	3	–	–	–	–	–	–	–	–	–	–	–	2	–	–	–	5		4
28	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
29	–	6	1	2	–	26	17	2	3	10	1	25	3	6	4	–	–	240		3
30	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
31	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	6		4
32	1	–	–	1	1	2	5	3	1	3	–	3	2	–	–	–	–	53		3
33	12	17	3	9	9	–	–	16	21	12	2	11	–	6	–	–	–	348		3
34	–	2	2	–	–	–	–	–	–	–	–	–	–	3	1	–	–	15		3
35	–	5	–	–	–	1	2	–	4	–	3	–	–	2	–	–	–	67		3
36	13	10	31	11	12	7	11	14	3	16	4	11	13	23	10	–	–	2,306		3
37																	–	–		N/A
38	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	9		3
39	31	49	36	28	62	38	17	20	13	12	8	27	36	45	21	8	–	586		3
40	12	6	11	13	15	5	8	11	7	4	3	3	2	–	–	–	–	428		3
41	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1		3
42	–	2	3	2	4	5	6	7	1	–	3	–	–	6	3	–	–	44		4
43	–	–	–	2	–	–	–	–	–	1	–	–	–	–	–	–	–	5		4
44	162	205	153	163	172	161	162	153	205	148	120	131	168	166	153	14	–	6,473		3
45	34	31	39	40	50	40	39	49	24	34	21	17	9	30	28	3	–	981		3
46	34	12	26	15	13	18	17	16	16	17	9	17	15	24	25	14	–	582		3
47	134	61	55	50	66	55	58	48	26	53	64	58	51	63	38	1	–	4,134		3
48	142	161	196	136	185	158	91	66	59	44	60	92	78	95	59	22	–	2,811		3
49	–	2	–	3	3	2	4	5	–	–	2	–	4	2	–	–	–	41		4
50	142	161	196	136	185	158	91	66	59	44	60	92	78	95	59	22	–	2,811		3
51	4	4	4	3	3	2	2	3	2	–	2	1	2	1	–	–	–	1,047		3
52	36	44	55	50	46	45	31	28	14	20	17	18	24	27	22	5	–	926		3
53	2	4	3	4	5	6	3	6	4	4	8	5	2	5	1	–	–	221		3
54	1,408	1,463	1,623	1,671	1,564	1,703	1,335	1,061	1,111	888	1,174	969	1,166	1,187	1,568	362	–	88,305		3
55	13	24	8	14	14	7	11	26	23	16	5	14	2	17	4	–	–	476		3
56	10	4	8	1	4	1	5	8	2	5	11	7	6	5	11	14	–	109		3
57	–	–	–	–	–	–	–	–	–	3	–	–	–	–	–	–	–	3		4
58	–	–	–	–	–	–	–	1	–	1	3	–	–	–	1	–	–	6		4
59	52	87	144	107	131	101	52	42	25	26	23	21	9	65	678	38	–	2,209		3
60																	–	–		N/A

Company Name	**Aurora Energy Ltd**
For Year Ended	**31 March 2017**
Network / Sub-network Name	**Dunedin Sub-network**

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

8 **Disclosure Year (year ended)** 31 March 2017 — **Number of assets at disclosure year end by installation date**

sch ref	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	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.	–	9	1,636	6,005	2,918	2,134	806	23	11	77	31	11	31	32	23	17	11	41	45	157	164	263	315	341	226	–	15,327		4
11	All	Overhead Line	Wood poles	No.	1,157	1,336	2,252	3,284	1,208	1,336	1,765	194	128	118	123	93	123	130	114	171	102	91	111	59	50	17	18	14	24	–	14,018		4
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	62	–	62	15	3	–	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	144		3
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4	–	–	–	–	4		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	27	2	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	36		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	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.		1	5	3	6	2	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	18		4
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0	–	–	–	–	–	–	–	–	–	–		N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		4
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	37	22	4	–	6	–	–	–	–	–	–	–	–	–	–	2	8	–	25	3	–	4	–	–	111		3
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
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.	–	32	46	37	78	2	13	–	–	–	17	–	9	–	–	–	11	17	–	–	–	–	–	–	–	–	262		3
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		3
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	10	6	11	2	1	–	–	–	–	–	–	–	1	–	–	2	–	2	–	–	–	–	–	–	35		3
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2	34	120	250	138	68	65	5	4	6	5	6	5	1	4	6	5	1	2	–	2	1	1	–	–	–	731		3
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km																										–	–		N/A
38	HV	Distribution Line	SWER conductor	km	–	–	6	2	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	9		3
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	–	–	–	–	–	4	3	2	2	3	2	4	2	2	1	1	1	1	1	–	1	1	2	1	–	34		3
40	HV	Distribution Cable	Distribution UG PILC	km	–	8	36	54	68	50	29	2	1	1	1	2	3	1	1	3	3	6	4	2	3	2	–	–	–	–	280		3
41	HV	Distribution Cable	Distribution Submarine Cable	km	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1		3
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	–	–	–	–	–	–	–	–	–	–	–	–	1	3	–	–	3	1	–	1	–	–	3	1	–	–	13		4
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	1	–	1	–	–	–	–	–	2	–	–	–	–	–	1	–	–	–	–	–	–	–	5		4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	–	20	71	600	435	427	486	14	19	27	40	29	49	44	29	21	32	18	23	29	29	53	37	49	3	–	2,584		3
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	10	104	68	70	65	5	9	6	14	3	7	3	7	12	13	21	9	15	2	–	3	5	–	–	451		3
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	1	42	79	90	7	3	8	4	11	6	3	2	7	6	8	6	3	11	8	4	11	3	–	323		3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	4	14	122	587	270	187	193	6	21	36	17	19	31	29	12	11	21	8	23	16	21	16	26	12		–	1,702		3
48	HV	Distribution Transformer	Ground Mounted Transformer	No.			29	154	232	114	106	3	11	18	21	19	23	19	15	18	20	24	13	16	19	17	18	18	3	–	930		3
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	5	3	2	–	–	–	–	–	–	2	–	–	–	–	–	–	–	–	–	–	–	–	–	12		4
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.			29	154	232	114	106	3	11	18	21	19	23	19	15	18	20	24	13	16	19	17	18	18	3	–	930		3
51	LV	LV Line	LV OH Conductor	km	52	26	69	191	168	151	132	4	2	3	4	3	3	2	2	1	2	2	–	2	1	1	1	–	–	–	822		3
52	LV	LV Cable	LV UG Cable	km	–	–	2	26	42	37	36	3	4	5	6	8	14	9	10	5	9	5	7	6	8	7	7	8	1	–	265		3
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	5	3	4	10	9	10	86	–	–	–	–	–	1	1	1	2	4	2	2	6	3	2	2	1	–	–	154		3
54	LV	Connections	OH/UG consumer service connections	No.	12,847	3,657	6,909	8,617	6,951	4,483	4,717	288	262	359	429	490	490	506	549	398	390	458	356	400	379	407	366	443	108	–	55,259		3
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	35	46	39	83	2	14	–	–	1	17	–	12	4	2	5	14	18	4	1	2	–	3	1	–	–	303		3
56	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	–	–	–	–	–	3	–	–	2	–	–	1	–	1	–	–	–	–	–	8	5	5	2	5	13	–	45		3
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	3	–	–	–	–	–	–	–	3		4
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	3	–	–	–	–	–	–	3		4
59	All	Load Control	Relays	No	–	1	3	47	60	73	89	2	2	5	3	3	3	5	7	5	5	7	11	7	4	3	59	671	37	–	1,112		3
60	All	Civils	Cable Tunnels	km																										–	–		N/A

Company Name	**Aurora Energy Ltd**
For Year Ended	**31 March 2017**
Network / Sub-network Name	**Central Otago Sub-network**

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

8 **Disclosure Year (year ended)** 31 March 2017

Number of assets at disclosure year end by installation date

sch ref	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	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
9																																	
10	All	Overhead Line	Concrete poles / steel structure	No.	–	16	86	428	1,824	1,044	1,022	65	87	121	98	67	83	152	149	195	94	112	185	430	310	417	349	295	176	–	7,805		4
11	All	Overhead Line	Wood poles	No.	–	32	169	5,161	4,495	2,516	1,605	132	102	267	323	222	142	197	175	150	225	251	233	92	51	87	72	61	42	–	16,802		4
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	9	3	11	93	72	38	126	–	–	–	–	–	–	6	–	–	4	4	11	–	–	3	2	–	–		382		3
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km																											–		N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	–	1	7	–	–	–	–	1	1	–	2	2	1	–	–	1	–	–	–	1	–	–	17		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	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.		–	–	–	1	3	3	–	–	–	–	–	–	–	–	–	1	–	1	–	1	–	2	–	–	–	12		4
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0	–	–	–	–	–	–	–	–	–	–		N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	–	–	–	–	–	3	–	–	–	–	–	–	–	–	–	–	–	2	–	–	–	5		4
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	14	3	3	27	18	–	–	–	6	1	2	–	26	17	2	1	2	1	–	–	6	–	–	–	129		3
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
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	–	8	7	–	–	–	–	–	1	–	–	–	3	1	–	–	1	2	–	–	–	–	30		3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	–	2	7	13	–	–	12	–	3	–	9	–	–	5	4	12	2	11	–	6	–	–	–	86		3
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	4	2	1	–	–	–	–	–	2	2	–	–	–	–	–	–	–	–	–	–	3	1	–	–	15		3
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	1	5	7	4	3	–	–	–	5	–	–	–	–	2	–	2	–	1	–	–	2		–	–	32		3
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	75	102	201	174	278	315	275	6	6	7	5	25	6	11	3	5	9	2	14	4	9	12	22	10	–	–	1,576		3
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km																										–	–		N/A
38	HV	Distribution Line	SWER conductor	km																										–	–		3
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	–	–	–	5	13	69	20	20	30	46	33	24	60	36	15	19	12	11	7	28	33	44	19	7	–	551		3
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	–	–	27	40	6	7	11	5	9	8	15	4	5	7	1	1	1	–	–	–	–	–	–	147		3
41	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		3
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	–	–	–	–	–	–	2	–	–	–	2	3	1	1	5	6	4	–	–	2	–	–	3	2	–	–	31		4
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1	8	37	129	227	441	843	138	141	135	165	124	114	128	132	141	121	187	125	91	102	115	129	104	11	–	3,889		3
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	1	–	–	–	–	9	112	24	16	28	17	36	31	47	33	27	36	3	25	7	15	9	27	23	3	–	529		3
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	–	3	8	41	6	14	26	8	15	8	10	16	10	10	8	11	6	6	7	20	14	11	–	258		3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	57	62	197	260	299	338	564	42	30	98	44	36	19	37	43	47	27	18	30	48	37	35	37	26	1	–	2,432		3
48	HV	Distribution Transformer	Ground Mounted Transformer	No.			2	13	52	64	221	70	96	124	140	172	113	166	143	73	46	35	31	44	73	61	77	41	19	–	1,876		3
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	1	–	2	1	–	–	–	2	–	1	3	2	4	5	–	–	2	–	4	2	–	–	–	29		4
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.			2	13	52	64	221	70	96	124	140	172	113	166	143	73	46	35	31	44	73	61	77	41	19	–	1,876		3
51	LV	LV Line	LV OH Conductor	km	4	16	40	71	44	20	23	1	–	1	–	1	–	1	–	1	1	–	–	–	–	1	–	–	–	–	225		3
52	LV	LV Cable	LV UG Cable	km	–	–	–	–	1	136	120	18	18	31	39	48	31	36	36	27	18	9	14	10	10	17	19	15	3	–	656		3
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	–	–	1	17	13	2	1	2	4	3	3	4	4	1	2	3	2	2	3	1	3	–	–	–	71		3
54	LV	Connections	OH/UG consumer service connections	No.				6	6	5	17,702	702	900	1,049	1,034	1,133	1,179	1,043	1,138	923	664	640	520	766	584	755	817	1,123	254	–	32,943		3
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	8	5	3	15	28	–	–	12	7	8	2	10	5	6	12	5	12	4	12	2	14	3	–	–	173		3
56	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	–	–	–	–	–	–	–	–	2	10	4	7	1	3	1	5	8	2	5	3	2	1	3	6	1	–	64		3
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		4
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	1	–	–	–	–	1	–	–	3		4
59	All	Load Control	Relays	No	–	–	–	4	19	54	179	37	38	47	84	141	99	126	94	47	37	18	15	16	17	6	6	7	1	–	1,092		3
60	All	Civils	Cable Tunnels	km																										–	–		N/A

Company Name	**Aurora Energy Ltd**
For Year Ended	**31 March 2017**
Network / Sub-network Name	**Total Network**

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	418	92	510
14	SWER (all SWER voltages)	9	–	9
15	22kV (other than SWER)	–	–	–
16	6.6kV to 11kV (inclusive—other than SWER)	2,306	1,013	3,319
17	Low voltage (< 1kV)	1,093	1,095	2,188
18	**Total circuit length (for supply)**	3,934	2,201	6,135
19				
20	Dedicated street lighting circuit length (km)	50	107	157
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			53
22				
23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**	
24	Urban	1,311	33%	
25	Rural	2,521	64%	
26	Remote only	–	–	
27	Rugged only	102	3%	
28	Remote and rugged	–	–	
29	Unallocated overhead lines	–	–	
30	**Total overhead length**	3,934	100%	
31				
32		**Circuit length (km)**	**(% of total circuit length)**	
33	Length of circuit within 10km of coastline or geothermal areas (where known)	2,266	37%	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	240	6%	

Company Name	**Aurora Energy Ltd**
For Year Ended	**31 March 2017**
Network / Sub-network Name	**Dunedin Sub-network**

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	–	–	–
13	33kV	144	76	220
14	SWER (all SWER voltages)	9	–	9
15	22kV (other than SWER)	–	–	–
16	6.6kV to 11kV (inclusive—other than SWER)	730	315	1,045
17	Low voltage (< 1kV)	865	372	1,237
18	**Total circuit length (for supply)**	1,748	763	2,511
19				
20	Dedicated street lighting circuit length (km)	47	175	222
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			4
22				
23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**	
24	Urban	1,072	61%	
25	Rural	662	38%	
26	Remote only	–	–	
27	Rugged only	14	1%	
28	Remote and rugged	–	–	
29	Unallocated overhead lines	–	–	
30	**Total overhead length**	1,748	100%	
31				
32		**Circuit length (km)**	**(% of total circuit length)**	
33	Length of circuit within 10km of coastline or geothermal areas (where known)	2,266	90%	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	87	5%	

Company Name	**Aurora Energy Ltd**
For Year Ended	**31 March 2017**
Network / Sub-network Name	**Central Otago Sub-network**

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	274	16	290
14	SWER (all SWER voltages)	–	–	–
15	22kV (other than SWER)	–	–	–
16	6.6kV to 11kV (inclusive—other than SWER)	1,576	698	2,274
17	Low voltage (< 1kV)	228	723	951
18	**Total circuit length (for supply)**	2,186	1,438	3,624
19				
20	Dedicated street lighting circuit length (km)	3	68	71
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			49
22				

23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**
24	Urban	238	11%
25	Rural	1,860	85%
26	Remote only	–	–
27	Rugged only	88	4%
28	Remote and rugged	–	–
29	Unallocated overhead lines	–	–
30	**Total overhead length**	2,186	100%
31			
32		**Circuit length (km)**	**(% of total circuit length)**
33	Length of circuit within 10km of coastline or geothermal areas (where known)	–	–
34		**Circuit length (km)**	**(% of total overhead length)**
35	Overhead circuit requiring vegetation management	153	7%

Company Name	**Aurora Energy Ltd**
For Year Ended	**31 March 2017**

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)
9	Heritage Estate (Te Anau)	105	82
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 Ltd**
For Year Ended	**31 March 2017**
Network / Sub-network Name	**Total Network**

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*			
10	*Consumer types defined by EDB**		**Number of connections (ICPs)**	
11	Residential		1,165	
12	Load Group 0		(13)	
13	Load Group 0A		132	
14	Load Group 1A		14	
15	Load Group 1		14	
15a	Load Group 2		71	
15b	Load Group 3		7	
15c	Load Group 3A			
15d	Load Group 4		6	
15e	Load Group 5		229	
15f	Street Lighting		229	
15g	Distributed Unmetered Load (excl. Street Lighting)		229	
16	** include additional rows if needed*			
17	**Connections total**		2,084	
18				
19	**Distributed generation**			
20	Number of connections made in year		133	**connections**
21	Capacity of distributed generation installed in year		0.48	**MVA**
22	**9e(ii): System Demand**			
23				
24				
25	**Maximum coincident system demand**		**Demand at time of maximum coincident demand (MW)**	
26	GXP demand		229	
27	Distributed generation output at HV and above	*plus*	62	
28	**Maximum coincident system demand**		291	
29	Net transfers to (from) other EDBs at HV and above	*less*	(0)	
30	**Demand on system for supply to consumers' connection points**		291	
31	**Electricity volumes carried**		**Energy (GWh)**	
32	Electricity supplied from GXPs		1,077	
33	Electricity exports to GXPs	*less*	46	
34	Electricity supplied from distributed generation	*plus*	332	
35	Net electricity supplied to (from) other EDBs	*less*	(1)	
36	**Electricity entering system for supply to consumers' connection points**		1,364	
37	Total energy delivered to ICPs	*less*	1,284	
38	**Electricity losses (loss ratio)**		80	5.9%
39				
40	**Load factor**		0.53	
41	**9e(iii): Transformer Capacity**			
42			**(MVA)**	
43	Distribution transformer capacity (EDB owned)		880	
44	Distribution transformer capacity (Non-EDB owned, estimated)		73	
45	**Total distribution transformer capacity**		953	
46				
47	**Zone substation transformer capacity**		898	

Company Name	**Aurora Energy Ltd**
For Year Ended	**31 March 2017**
Network / Sub-network Name	**Dunedin Sub-network**

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	Residential	322
12	Load Group 0	(4)
13	Load Group 0A	(7)
14	Load Group 1A	2
15	Load Group 1	(32)
15a	Load Group 2	13
15b	Load Group 3	
15c	Load Group 3A	(1)
15d	Load Group 4	5
15e	Load Group 5	
15f	Street Lighting	
15g	Distributed Unmetered Load (excl. Street Lighting)	
16	** include additional rows if needed*	
17	**Connections total**	298

18

19 ### Distributed generation

sch ref			
20	Number of connections made in year	31	**connections**
21	Capacity of distributed generation installed in year	0.10	**MVA**

22 ## 9e(ii): System Demand

23

24

sch ref			Demand at time of maximum coincident demand (MW)
25		**Maximum coincident system demand**	
26		GXP demand	161
27	*plus*	Distributed generation output at HV and above	24
28		**Maximum coincident system demand**	185
29	*less*	Net transfers to (from) other EDBs at HV and above	–
30		**Demand on system for supply to consumers' connection points**	185

sch ref			Energy (GWh)	
31		**Electricity volumes carried**		
32		Electricity supplied from GXPs	689	
33	*less*	Electricity exports to GXPs	4	
34	*plus*	Electricity supplied from distributed generation	160	
35	*less*	Net electricity supplied to (from) other EDBs	–	
36		**Electricity entering system for supply to consumers' connection points**	846	
37	*less*	Total energy delivered to ICPs	796	
38		**Electricity losses (loss ratio)**	49	5.8%
39				
40		**Load factor**	0.52	

41 ## 9e(iii): Transformer Capacity

sch ref		(MVA)
43	Distribution transformer capacity (EDB owned)	480
44	Distribution transformer capacity (Non-EDB owned, estimated)	49
45	**Total distribution transformer capacity**	528
46		
47	**Zone substation transformer capacity**	610

Company Name	**Aurora Energy Ltd**
For Year Ended	**31 March 2017**
Network / Sub-network Name	**Central Otago Sub-network**

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

9e(i): Consumer Connections

Number of ICPs connected in year by consumer type

sch ref	*Consumer types defined by EDB**	Number of connections (ICPs)
11	Residential	835
12	Load Group 0	(9)
13	Load Group 0A	137
14	Load Group 1A	12
15	Load Group 1	46
15a	Load Group 2	58
15b	Load Group 3	7
15c	Load Group 3A	1
15d	Load Group 4	1
15e	Load Group 5	
15f	Street Lighting	
15g	Distributed Unmetered Load (excl. Street Lighting)	
16	** include additional rows if needed*	
17	**Connections total**	1,088

Distributed generation

sch ref			
20	Number of connections made in year	102	**connections**
21	Capacity of distributed generation installed in year	0.38	**MVA**

9e(ii): System Demand

sch ref			Demand at time of maximum coincident demand (MW)
25		**Maximum coincident system demand**	
26		GXP demand	88
27	*plus*	Distributed generation output at HV and above	22
28		**Maximum coincident system demand**	110
29	*less*	Net transfers to (from) other EDBs at HV and above	–
30		**Demand on system for supply to consumers' connection points**	110

sch ref			Energy (GWh)	
31		**Electricity volumes carried**		
32		Electricity supplied from GXPs	388	
33	*less*	Electricity exports to GXPs	42	
34	*plus*	Electricity supplied from distributed generation	172	
35	*less*	Net electricity supplied to (from) other EDBs	–	
36		**Electricity entering system for supply to consumers' connection points**	518	
37	*less*	Total energy delivered to ICPs	487	
38		**Electricity losses (loss ratio)**	31	5.9%
40		**Load factor**	0.54	

9e(iii): Transformer Capacity

sch ref		(MVA)
43	Distribution transformer capacity (EDB owned)	394
44	Distribution transformer capacity (Non-EDB owned, estimated)	25,060
45	**Total distribution transformer capacity**	25,454
47	**Zone substation transformer capacity**	288

Company Name	**Aurora Energy Ltd**
For Year Ended	**31 March 2017**
Network / Sub-network Name	**Total Network**

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**		
9	**Interruptions by class**	**Number of interruptions**	
10	Class A (planned interruptions by Transpower)		
11	Class B (planned interruptions on the network)	391	
12	Class C (unplanned interruptions on the network)	466	
13	Class D (unplanned interruptions by Transpower)	1	
14	Class E (unplanned interruptions of EDB owned generation)		
15	Class F (unplanned interruptions of generation owned by others)		
16	Class G (unplanned interruptions caused by another disclosing entity)		
17	Class H (planned interruptions caused by another disclosing entity)		
18	Class I (interruptions caused by parties not included above)		
19	**Total**	858	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	342	124
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)		
26	Class B (planned interruptions on the network)	0.31	62.5
27	Class C (unplanned interruptions on the network)	1.26	107.0
28	Class D (unplanned interruptions by Transpower)	0.14	15.6
29	Class E (unplanned interruptions of EDB owned generation)		
30	Class F (unplanned interruptions of generation owned by others)		
31	Class G (unplanned interruptions caused by another disclosing entity)		
32	Class H (planned interruptions caused by another disclosing entity)		
33	Class I (interruptions caused by parties not included above)		
34	**Total**	1.71	185.1
35			
36	**Normalised SAIFI and SAIDI**	**Normalised SAIFI**	**Normalised SAIDI**
37	Classes B & C (interruptions on the network)	1.36	108.5
38			
39	**Quality path normalised reliability limit**	**SAIFI reliability limit**	**SAIDI reliability limit**
40	SAIFI and SAIDI limits applicable to disclosure year*	1.45	83.4
41	** not applicable to exempt EDBs*		

Company Name	**Aurora Energy Ltd**
For Year Ended	**31 March 2017**
Network / Sub-network Name	**Total Network**

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.

42 **10(ii): Class C Interruptions and Duration by Cause**

43

44	**Cause**	**SAIFI**	**SAIDI**
45	Lightning	0.02	2.2
46	Vegetation	0.13	19.4
47	Adverse weather	0.18	32.8
48	Adverse environment	0.00	5.1
49	Third party interference	0.11	6.4
50	Wildlife	0.01	0.7
51	Human error	0.08	3.3
52	Defective equipment	0.35	22.5
53	Cause unknown	0.35	14.5
54			

55 **10(iii): Class B Interruptions and Duration by Main Equipment Involved**

56

57	**Main equipment involved**	**SAIFI**	**SAIDI**
58	Subtransmission lines	0.00	0.0
59	Subtransmission cables		
60	Subtransmission other		
61	Distribution lines (excluding LV)	0.24	53.3
62	Distribution cables (excluding LV)	0.04	6.3
63	Distribution other (excluding LV)	0.03	2.9

64 **10(iv): Class C Interruptions and Duration by Main Equipment Involved**

65

66	**Main equipment involved**	**SAIFI**	**SAIDI**
67	Subtransmission lines	0.10	10.6
68	Subtransmission cables		
69	Subtransmission other	0.06	1.0
70	Distribution lines (excluding LV)	0.81	83.9
71	Distribution cables (excluding LV)	0.07	4.5
72	Distribution other (excluding LV)	0.22	7.1

73 **10(v): Fault Rate**

74	**Main equipment involved**	**Number of Faults**	**Circuit length (km)**	**Fault rate (faults per 100km)**
75	Subtransmission lines	10		–
76	Subtransmission cables			–
77	Subtransmission other	5		
78	Distribution lines (excluding LV)	273		–
79	Distribution cables (excluding LV)	17		–
80	Distribution other (excluding LV)	166		
81	**Total**	471		

Company Name	**Aurora Energy Ltd**
For Year Ended	**31 March 2017**
Network / Sub-network Name	**Dunedin Sub-network**

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

sch ref			
8	**10(i): Interruptions**		
9	**Interruptions by class**	**Number of interruptions**	
10	Class A (planned interruptions by Transpower)		
11	Class B (planned interruptions on the network)	108	
12	Class C (unplanned interruptions on the network)	128	
13	Class D (unplanned interruptions by Transpower)		
14	Class E (unplanned interruptions of EDB owned generation)		
15	Class F (unplanned interruptions of generation owned by others)		
16	Class G (unplanned interruptions caused by another disclosing entity)		
17	Class H (planned interruptions caused by another disclosing entity)		
18	Class I (interruptions caused by parties not included above)		
19	**Total**	236	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	82	46
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)		
26	Class B (planned interruptions on the network)	0.22	52.8
27	Class C (unplanned interruptions on the network)	0.66	53.7
28	Class D (unplanned interruptions by Transpower)		
29	Class E (unplanned interruptions of EDB owned generation)		
30	Class F (unplanned interruptions of generation owned by others)		
31	Class G (unplanned interruptions caused by another disclosing entity)		
32	Class H (planned interruptions caused by another disclosing entity)		
33	Class I (interruptions caused by parties not included above)		
34	**Total**	0.88	106.5
35			
36	**Normalised SAIFI and SAIDI**	**Normalised SAIFI**	**Normalised SAIDI**
37	Classes B & C (interruptions on the network)	N/A	N/A
38			
39	**Quality path normalised reliability limit**	**SAIFI reliability limit**	**SAIDI reliability limit**
40	SAIFI and SAIDI limits applicable to disclosure year*	N/A	N/A
41	** not applicable to exempt EDBs*		

Company Name	**Aurora Energy Ltd**
For Year Ended	**31 March 2017**
Network / Sub-network Name	**Dunedin Sub-network**

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.

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

Cause	SAIFI	SAIDI
Lightning	0.03	3.4
Vegetation	0.13	18.2
Adverse weather	0.12	13.3
Adverse environment	0.00	0.0
Third party interference	0.07	3.7
Wildlife	0.02	0.7
Human error	0.03	0.5
Defective equipment	0.20	9.3
Cause unknown	0.05	4.5

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)	0.17	47.9
Distribution cables (excluding LV)	0.03	3.6
Distribution other (excluding LV)	0.02	1.3

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.08	12.9
Subtransmission cables		
Subtransmission other	0.04	0.6
Distribution lines (excluding LV)	0.37	33.5
Distribution cables (excluding LV)	0.03	0.8
Distribution other (excluding LV)	0.15	6.0

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	1		–
Subtransmission cables			–
Subtransmission other	3		
Distribution lines (excluding LV)	72		–
Distribution cables (excluding LV)	8		–
Distribution other (excluding LV)	48		
Total	132		

Company Name	**Aurora Energy Ltd**
For Year Ended	**31 March 2017**
Network / Sub-network Name	**Central Otago Sub-network**

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**		
9	**Interruptions by class**	**Number of interruptions**	
10	Class A (planned interruptions by Transpower)		
11	Class B (planned interruptions on the network)	283	
12	Class C (unplanned interruptions on the network)	338	
13	Class D (unplanned interruptions by Transpower)	1	
14	Class E (unplanned interruptions of EDB owned generation)		
15	Class F (unplanned interruptions of generation owned by others)		
16	Class G (unplanned interruptions caused by another disclosing entity)		
17	Class H (planned interruptions caused by another disclosing entity)		
18	Class I (interruptions caused by parties not included above)		
19	**Total**	622	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	260	78
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)		
26	Class B (planned interruptions on the network)	0.47	79.1
27	Class C (unplanned interruptions on the network)	2.28	197.7
28	Class D (unplanned interruptions by Transpower)	0.38	42.7
29	Class E (unplanned interruptions of EDB owned generation)		
30	Class F (unplanned interruptions of generation owned by others)		
31	Class G (unplanned interruptions caused by another disclosing entity)		
32	Class H (planned interruptions caused by another disclosing entity)		
33	Class I (interruptions caused by parties not included above)		
34	**Total**	3.13	319.4
35			
36	**Normalised SAIFI and SAIDI**	**Normalised SAIFI**	**Normalised SAIDI**
37	Classes B & C (interruptions on the network)	N/A	N/A
38			
39	**Quality path normalised reliability limit**	**SAIFI reliability limit**	**SAIDI reliability limit**
40	SAIFI and SAIDI limits applicable to disclosure year*	N/A	N/A
41	** not applicable to exempt EDBs*		

Company Name	**Aurora Energy Ltd**
For Year Ended	**31 March 2017**
Network / Sub-network Name	**Central Otago Sub-network**

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.

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

Cause	SAIFI	SAIDI
Lightning	0.00	0.2
Vegetation	0.14	21.3
Adverse weather	0.29	66.0
Adverse environment	0.01	13.8
Third party interference	0.19	10.9
Wildlife	0.01	0.8
Human error	0.18	8.1
Defective equipment	0.59	45.0
Cause unknown	0.87	31.5

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.00	0.0
Subtransmission cables		
Subtransmission other		
Distribution lines (excluding LV)	0.36	62.7
Distribution cables (excluding LV)	0.07	10.7
Distribution other (excluding LV)	0.05	5.6

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.14	6.8
Subtransmission cables		
Subtransmission other	0.09	1.7
Distribution lines (excluding LV)	1.55	169.5
Distribution cables (excluding LV)	0.14	10.8
Distribution other (excluding LV)	0.36	8.9

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	9		–
Subtransmission cables			–
Subtransmission other	2		
Distribution lines (excluding LV)	201		–
Distribution cables (excluding LV)	9		–
Distribution other (excluding LV)	120		0
Total	341		

Company Name	Aurora Energy Limited
For Year Ended	31 March 2017

Schedule 14 Mandatory Explanatory Notes

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 subclauses 2.5.1(1)(f),and 2.5.2(1)(e).

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 subclause 2.7.1(2).

Box 1: Explanatory comment on return on investment

The 2017 ROI continues the trend of recent years of being well below the estimate of WACC used to set Aurora's price path. The 2017 ROI is just above the 75th percentile of WACC that has been estimated by the Commerce Commission for Information Disclosure purposes. There have been no items reclassified in accordance with clause 2.7.1(2).

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 regulated income (other than gains / (losses) on asset disposals), as disclosed in 3(i) of Schedule 3

    5.2 information on reclassified items in accordance with subclause 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* $1,324
- *Transmission Charge Recovered* $1,355
- *Other income incl. accident damage* $ 582
- *Service Failure Recoveries* $ 207

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 subclause 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 subclause 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 2017 disclosure year, related party transactions have been recorded at the directly attributable cost incurred by Delta

The impact of these adjustments are as follows ($000):	*2017 Yr*
Original cost (and regulatory tax value)	*28,278*
Less customer contributions	*(3,499)*
Less margin/ indirect cost on related party capex	*(6,185)*

Value RAB assets commissioned	*18,594*

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 material items recorded in the following asterisked categories of 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 $2,918,150 of customer contributions that are 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 $154,048, being the movement in doubtful debts.

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

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

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

The $774,000 shown in the line 'Tax effect of other temporary differences' is (in $000):

Value of customer contributions (as above)	*$2,918*
Less doubtful debts (as above)	*($ 154)*

Sub-total of differences	*$2,764*
Tax effect at 28%	*$ 774*

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 subclause 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 subclause 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.

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 subclause 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 expenditure on assets 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 subclause 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'.

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

Actual capital expenditure is significantly higher than the capital expenditure projection determined by the Commerce Commission, and used to set Aurora's price path. Limited workable options in the prescribed methods for valuing related party transactions continues to suppress recognisable capital expenditure, as the majority of transactions are valued at directly attributable cost, which yields a demonstrably lower value than if determined by market valuation.

	Actual 2017 $000	Projection* 2017 $000	Variance $000	%
Gross capex	$30,138			
less Capital Contributions	-$3,499			
less Related Party adjustments	-$6,185			
Total capex	$ 20,454	$ 16,971	$ 3,483	21%

* Commerce Commission projection, nominal dollars. Source: Electricity Distribution Business Price-Quality Regulation 1 April 2015 Reset Model 4. Capex projections. Final Determination Version. Version 2.0. 28 November 2014

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 operational expenditure, as reported in 6b(i) of Schedule 6b;

    14.2 Information on reclassified items in accordance with subclause 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, actual operational expenditure is significantly higher than the operational expenditure projection determined by the Commerce Commission, and used to set Aurora's price path.

	Actual 2017 $000	Projection* 2017 $000	Variance $000	%
Network opex	$ 16,041	$ 11,270	$ 4,771	42%
Non-network opex	$ 11,431	$ 11,577	-$ 146	-1%
Total opex	$ 27,472	$ 22,847	$ 4,625	20%

* Commerce Commission projection, nominal dollars. Source: Electricity Distribution Business Price-Quality Regulation 1 April 2015 Reset Model 3. Opex projections. Final Determination Version. Version 2.0. 28 November 2014

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 subclause 2.7.1(2).

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

Capital expenditure on consumer connections reflects continuing high levels of development activity, mainly within the Central Otago subnetwork. The variance to forecast can be attributed, in part, by competition for new connections from Electricity Southland Limited (ESL) in the Frankton Flats suburb of Queenstown. Interested persons will be unable, however, to check this against ESL disclosures, as their owners have structured their affairs so that they combine their disclosures with OtagoNet, and avoid separate and transparent disclosure.

'Asset replacement and renewal' expenditure is significantly above forecast. This variance is largely attributable to Aurora's fast-tracked pole programme which commenced in December 2016 and was not forecast.

Asset relocation activity has been slightly lower than expected, attributable to no particular project In general, 'Consumer connection', 'system growth' and 'asset relocation' expenditure is generally driven by external factors and less controllable than other categories.

Overall maintenance expenditure was greater than that forecast for the disclosure period. The increase in service interruptions and emergencies reflects the reliability performance of the Aurora network during the reporting period. Further commentary on reliability performance is provided in Box 14, below.

Non-network operational expenditure has been significantly under-forecast for the reporting period. As noted in Box 11 above, the level of non-network operational expenditure is near Commerce Commission expectations.

Information relating to revenues 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 clause 2.4.1 and subclause 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	*$91.020 million (2016 pricing methodology)*
Reported – Schedule 8 (Total Business)	*$92.640 million*
Difference	*$1.620 million above 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 on a notional quantities basis to ensure that allowable notional revenue, as determined under the default price path, is not exceeded. Accordingly, target revenues are determined on quantities lagging two years behind the actual quantities reported in this assessment period.

In the assessment period, the volume of energy delivered to Residential consumers (the only consumer groups with volume-based pricing) decreased from the prior year (by 2.5%). Energy delivered to standard domestic in 2015/16 was 590.9GWh, compared to 576.4GWh in this assessment period.

The average number of Residential connections increased by 1.2%. Residential connection numbers disclosed in 2015/16 were 72,038, compared to 72,923 in this assessment period.

Accordingly, there was a material decrease in the average energy use per Residential consumer in this assessment period – 7,904kWh versus 8,168kWh in 2015/16.

At the same time, the average number of General connections, that are priced predominantly on the basis of demand and capacity, increased by 1.8%, driven mainly by activity on the Central Otago subnetwork (4.0%).

The distinction between Residential and General connections is explained in section 10 (p26) of Aurora's Use-of-System Pricing Methodology, available from http://www.auroraenergy.co.nz/disclosures/pricing/

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

Supplementing the definitions contained in the Electricity Distribution Information Disclosure Determination 2012, the following categorisations are disclosed:

- *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.*

Specific commentary on matters relating to Aurora's reliability performance for the disclosure years is contained in section 6.2 (p6) of Aurora's Annual Compliance Statement (2017), available from http://www.auroraenergy.co.nz/disclosures/price-quality-path/

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.

Material Damage Insurance cover has been obtained in respect of high value Distribution assets including distribution substations, transformers and switches.

Other Distribution assets including distribution poles, 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.

Amendments to previously disclosed information

19. In the box below, provide information about amendments to previously disclosed information disclosed in accordance with clause 2.12.1 in the last 7 years, including:

    19.1 a description of each error; and

    19.2 for each error, reference to the web address where the disclosure made in accordance with clause 2.12.1 is publicly disclosed.

Box 16: Disclosure of amendment to previously disclosed information

There have been no amendments to previously disclosed information.

Company Name	Aurora Energy Limited
For Year Ended	31 March 2017

Schedule 15 Voluntary Explanatory Notes

1. This schedule enables 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 and 2.5.2;

    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 $7,000 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.

SCHEDULE 18

Certification for Year-end Disclosures

Clause 2.9.2

We, Stephen Richard Thompson and David John Frow, being 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, 2.3.2, 2.4.21, 2.4.22, 2.5.1, 2.5.2, and 2.7.1 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, and 14 has been properly extracted from the Aurora Energy Limited accounting and other records sourced from its financial and non-financial systems, and that sufficient appropriate records have been retained.

Stephen Richard Thompson

David John Frow

30 August 2017

Independent Assurance Report

To the directors of Aurora Energy Limited and the Commerce Commission

The Auditor-General is the auditor of Aurora Energy Limited (the company). The Auditor-General has appointed me, Julian Tan, using the staff and resources of Audit New Zealand, to provide an opinion, on his behalf, on whether the information disclosed in schedules 1 to 4, 5a to 5g, 6a and 6b, 7, the system average interruption duration index ("SAIDI") and system average interruption frequency index ("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 2017, 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.

Our 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 (Revised) Assurance Engagements Other Than Audits or Reviews of Historical Financial Information and the Standard on Assurance Engagements 3100: Compliance Engagements issued by the External Reporting Board. Copies of these standards are available on the External Reporting Board's website.

These standards require that we comply with ethical requirements and plan and perform our assurance engagement to provide reasonable assurance about whether the Disclosure Information has been prepared in all material respects in accordance with the Determination.

We have performed procedures to obtain evidence about the amounts and disclosures in the Disclosure Information. The procedures selected depend on our 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, we considered internal control relevant to the company's preparation of the Disclosure Information in order to design 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.

Use of this report

This independent assurance report has been prepared solely for the directors of the company and for the Commerce Commission for the purpose of providing those parties with reasonable 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 a reasonable assurance 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 assurance report has been formed on the above basis.

Independence and quality control

When carrying out the engagement, we complied with the Auditor-General's:

- independence and other ethical requirements, which incorporate the independence and ethical requirements of Professional and Ethical Standard 1 (Revised) issued by the New Zealand Auditing and Assurance Standards Board; and

- quality control requirements, which incorporate the quality control requirements of Professional and Ethical Standard 3 (Amended) issued by the New Zealand Auditing and Assurance Standards Board.

We also complied with the independence requirements specified in the Determination.

The Auditor-General, and his 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, an assurance engagement in respect of the company's compliance statement prepared under the Electricity Distribution Services Default Price-Quality Path Determination 2015 NZCC 35 for the year ended 31 March 2017, 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;

- as far as appears from an examination, 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 Disclosure Information has been prepared, in all material respects, in accordance with the Determination.

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

Julian Tan
Audit New Zealand
On behalf of the Auditor-General
Dunedin, New Zealand
30 August 2017