
Information Disclosure

For the year ended 31 March 2016

Pursuant to the Electricity Distribution Information Disclosure Determination 2012

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Company Name **Aurora Energy Ltd**
For Year Ended **31 March 2016**

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

1(i): Expenditure metrics

Operational expenditure

Network

Non-network

Expenditure on assets

Network

Non-network

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)
19,313	293	86,569	4,283	28,793
11,815	179	52,960	2,620	17,614
7,498	114	33,609	1,663	11,178
22,279	338	99,868	4,941	33,216
22,279	338	99,868	4,941	33,216
–	–	–	–	–

1(ii): Revenue metrics

Total consumer line charge revenue

Standard consumer line charge revenue

Non-standard consumer line charge revenue

Revenue per GWh energy delivered to ICPs (\$/GWh)	Revenue per average no. of ICPs (\$/ICP)
70,239	1,065
70,176	1,054
76,983	49,384

1(iii): Service intensity measures

Demand density

Volume density

Connection point density

Energy intensity

49	Maximum coincident system demand per km of circuit length (for supply) (kW/km)
222	Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)
15	Average number of ICPs per km of circuit length (for supply) (ICPs/km)
15,162	Total energy delivered to ICPs per average number of ICPs (kWh/ICP)

1(iv): Composition of regulatory income

Operational expenditure

Pass-through and recoverable costs excluding financial incentives and wash-ups

Total depreciation

Total revaluations

Regulatory tax allowance

Regulatory profit/(loss) including financial incentives and wash-ups

Total regulatory income

(\$000)	% of revenue
25,173	26.57%
34,402	36.32%
12,318	13.00%
1,940	2.05%
6,758	7.13%
18,018	19.02%
94,729	

1(v): Reliability

Interruption rate

14.58	Interruptions per 100 circuit km
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Company Name **Aurora Energy Ltd**
 For Year Ended **31 March 2016**

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

sch ref		CY-2	CY-1	Current Year CY
		31 Mar 14 %	31 Mar 15 %	31 Mar 16 %
7	2(i): Return on Investment			
8				
9	ROI – comparable to a post tax WACC			
10	Reflecting all revenue earned	6.48%	5.15%	4.99%
11	Excluding revenue earned from financial incentives	6.48%	5.15%	4.99%
12	Excluding revenue earned from financial incentives and wash-ups	6.48%	5.15%	4.99%
13				
14	Mid-point estimate of post tax WACC	5.43%	6.10%	5.37%
15	25th percentile estimate	4.71%	5.39%	4.66%
16	75th percentile estimate	6.14%	6.82%	6.09%
17				
18				
19	ROI – comparable to a vanilla WACC			
20	Reflecting all revenue earned	7.17%	5.94%	5.63%
21	Excluding revenue earned from financial incentives	7.17%	5.94%	5.63%
22	Excluding revenue earned from financial incentives and wash-ups	7.17%	5.94%	5.63%
23				
24	WACC rate used to set regulatory price path	8.77%	8.77%	7.19%
25				
26	Mid-point estimate of vanilla WACC	6.11%	6.89%	6.02%
27	25th percentile estimate	5.39%	6.17%	5.30%
28	75th percentile estimate	6.83%	7.60%	6.74%
29				
30	2(ii): Information Supporting the ROI			
31				(\$000)
32	Total opening RAB value	330,597		
33	plus Opening deferred tax	(14,272)		
34	Opening RIV		316,325	
35				
36	Line charge revenue		91,267	
37				
38	Expenses cash outflow	59,575		
39	add Assets commissioned	20,446		
40	less Asset disposals	–		
41	add Tax payments	4,628		
42	less Other regulated income	3,462		
43	Mid-year net cash outflows		81,187	
44				
45	Term credit spread differential allowance		–	
46				
47	Total closing RAB value	340,665		
48	less Adjustment resulting from asset allocation	0		
49	less Lost and found assets adjustment	–		
50	plus Closing deferred tax	(16,402)		
51	Closing RIV		324,263	
52				
53	ROI – comparable to a vanilla WACC			5.63%
54				
55	Leverage (%)			44%
56	Cost of debt assumption (%)			5.26%
57	Corporate tax rate (%)			28%
58				
59	ROI – comparable to a post tax WACC			4.99%
60				

Company Name **Aurora Energy Ltd**
 For Year Ended **31 March 2016**

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).

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sch ref

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						–
July						–
August						–
September						–
October						–
November						–
December						–
January						–
February						–
March						–
Total	–	–	–	–	–	–

Tax payments

N/A

Term credit spread differential allowance

N/A

Closing RIV

N/A

Monthly ROI – comparable to a vanilla WACC

N/A

Monthly ROI – comparable to a post tax WACC

N/A

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

Year-end ROI – comparable to a vanilla WACC

5.52%

Year-end ROI – comparable to a post tax WACC

4.87%

** 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.*

2(v): Financial Incentives and Wash-Ups

Net recoverable costs allowed under incremental rolling incentive scheme

–

Purchased assets – avoided transmission charge

–

Energy efficiency and demand incentive allowance

–

Quality incentive adjustment

–

Other financial incentives

–

Financial incentives

–

Impact of financial incentives on ROI

–

Input methodology claw-back

–

Recoverable customised price-quality path costs

–

Catastrophic event allowance

–

Capex wash-up adjustment

–

Transmission asset wash-up adjustment

–

2013–2015 NPV wash-up allowance

–

Reconsideration event allowance

–

Other wash-ups

–

Wash-up costs

–

Impact of wash-up costs on ROI

–

Company Name **Aurora Energy Ltd**
For Year Ended **31 March 2016**

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

7	3(i): Regulatory Profit		(\$000)
8	Income		
9	Line charge revenue	91,267	
10	plus Gains / (losses) on asset disposals	–	
11	plus Other regulated income (other than gains / (losses) on asset disposals)	3,462	
12			
13	Total regulatory income	94,729	
14	Expenses		
15	less Operational expenditure	25,173	
16			
17	less Pass-through and recoverable costs excluding financial incentives and wash-ups	34,402	
18			
19	Operating surplus / (deficit)	35,154	
20			
21	less Total depreciation	12,318	
22			
23	plus Total revaluations	1,940	
24			
25	Regulatory profit / (loss) before tax	24,776	
26			
27	less Term credit spread differential allowance	–	
28			
29	less Regulatory tax allowance	6,758	
30			
31	Regulatory profit/(loss) including financial incentives and wash-ups	18,018	
32			
33	3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups		(\$000)
34	Pass through costs		
35	Rates	893	
36	Commerce Act levies	100	
37	Industry levies	243	
38	CPP specified pass through costs	–	
39	Recoverable costs excluding financial incentives and wash-ups		
40	Electricity lines service charge payable to Transpower	24,555	
41	Transpower new investment contract charges	–	
42	System operator services	–	
43	Distributed generation allowance	7,256	
44	Extended reserves allowance	–	
45	Other recoverable costs excluding financial incentives and wash-ups	1,355	
46	Pass-through and recoverable costs excluding financial incentives and wash-ups	34,402	
47			

Company Name **Aurora Energy Ltd**
 For Year Ended **31 March 2016**

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).

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sch ref

3(iii): Incremental Rolling Incentive Scheme

(\$000)

			CY-1 31 Mar 15	CY 31 Mar 16
51	Allowed controllable opex			
52	Actual controllable opex			
54	Incremental change in year			
56			Previous years' incremental change	Previous years' incremental change adjusted for inflation
57	CY-5 31 Mar 11			
58	CY-4 31 Mar 12			
59	CY-3 31 Mar 13			
60	CY-2 31 Mar 14			
61	CY-1 31 Mar 15			
62	Net incremental rolling incentive scheme			-
64	Net recoverable costs allowed under incremental rolling incentive scheme			-

3(iv): Merger and Acquisition Expenditure

(\$000)

66	Merger and acquisition expenditure		-
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)		

3(v): Other Disclosures

(\$000)

71	Self-insurance allowance		-
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Company Name **Aurora Energy Ltd**
 For Year Ended **31 March 2016**

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

		for year ended				
		RAB 31 Mar 12 (\$000)	RAB 31 Mar 13 (\$000)	RAB 31 Mar 14 (\$000)	RAB 31 Mar 15 (\$000)	RAB 31 Mar 16 (\$000)
7	4(i): Regulatory Asset Base Value (Rolled Forward)					
10	Total opening RAB value	307,618	313,820	318,316	324,967	330,597
12	less Total depreciation	10,796	11,086	11,473	11,941	12,318
14	plus Total revaluations	4,832	2,696	4,879	273	1,940
16	plus Assets commissioned	12,735	12,886	13,374	17,298	20,446
18	less Asset disposals	569		129		—
20	plus Lost and found assets adjustment					—
22	plus Adjustment resulting from asset allocation					0
24	Total closing RAB value	313,820	318,316	324,967	330,597	340,665
26	4(ii): Unallocated Regulatory Asset Base					
29	Total opening RAB value		Unallocated RAB * (\$000)		RAB (\$000)	
30	less		330,597		330,597	
31	Total depreciation		12,318		12,318	
33	plus Total revaluations		1,940		1,940	
35	plus Assets commissioned (other than below)	5,143		5,143		
36	Assets acquired from a regulated supplier	—		—		
37	Assets acquired from a related party	15,303		15,303		
38	Assets commissioned		20,446		20,446	
40	less 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		340,665		340,665	
50	* 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.					

Company Name **Aurora Energy Ltd**
 For Year Ended **31 March 2016**

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

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52 4(iii): Calculation of Revaluation Rate and Revaluation of Assets

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CPI_t

CPI_t⁻⁴

Revaluation rate (%)

1,200

1,193

0.59%

Total opening RAB value

less Opening value of fully depreciated, disposed and lost assets

Total opening RAB value subject to revaluation

Total revaluations

Unallocated RAB *

(\$000)

(\$000)

RAB

(\$000)

(\$000)

330,597

—

330,597

—

330,597

330,597

1,940

1,940

66 4(iv): Roll Forward of Works Under Construction

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Works under construction—preceding disclosure year

plus Capital expenditure

less Assets commissioned

plus Adjustment resulting from asset allocation

Works under construction - current disclosure year

Highest rate of capitalised finance applied

Unallocated works under
construction

Allocated works under construction

22,926

20,446

15,492

22,926

20,446

15,492

17,972

17,972

Company Name **Aurora Energy Ltd**
For Year Ended **31 March 2016**

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

This schedule requires information on the calculation of the Regulatory Asset Base (RAB) value to the end of this disclosure year. This informs the ROI calculation in Schedule 2.

EDBs must provide explanatory comment on the value of their RAB in Schedule 14 (Mandatory Explanatory Notes). This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

4(v): Regulatory Depreciation

Depreciation - standard
Depreciation - no standard life assets
Depreciation - modified life assets
Depreciation - alternative depreciation in accordance with CPP
Total depreciation

Unallocated RAB *		RAB	
(\$000)	(\$000)	(\$000)	(\$000)
12,318		12,318	
	12,318		12,318

4(vi): Disclosure of Changes to Depreciation Profiles

(\$000 unless otherwise specified)

Asset or assets with changes to depreciation*	Reason for non-standard depreciation (text entry)	Depreciation charge for the period (RAB)	Closing RAB value under 'non-standard' depreciation	Closing RAB value under 'standard' depreciation

* Include additional rows if needed

4(vii): Disclosure by Asset Category

(\$000 unless otherwise specified)

	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
Total opening RAB value	13,657	9,095	59,008	49,274	124,892	51,201	19,589	3,881	—	330,597
less Total depreciation	563	373	2,247	2,345	3,869	1,747	999	175		12,318
plus Total revaluations	80	53	346	289	733	301	115	23		1,940
plus Assets commissioned	240	307	6,914	5,182	3,870	2,040	1,386	507		20,446
less Asset disposals										—
plus Lost and found assets adjustment										—
plus Adjustment resulting from asset allocation										—
plus Asset category transfers										—
Total closing RAB value	13,414	9,082	64,021	52,400	125,626	51,795	20,091	4,236	—	340,665
Asset Life										
Weighted average remaining asset life	24.2	24.4	25.0	21.0	32.3	29.5	19.6	18.0		(years)
Weighted average expected total asset life	67.5	49.2	40.2	45.8	48.3	50.0	35.8	17.1		(years)

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.

7	5a(i): Regulatory Tax Allowance			(\$000)
8	Regulatory profit / (loss) before tax			24,776
9				
10	<i>plus</i> Income not included in regulatory profit / (loss) before tax but taxable	2,568	*	
11	Expenditure or loss in regulatory profit / (loss) before tax but not deductible	(18)	*	
12	Amortisation of initial differences in asset values	4,993		
13	Amortisation of revaluations	893		
14				8,436
15				
16	<i>less</i> Total revaluations	1,940		
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	7,136		
21				9,076
22				
23	Regulatory taxable income			24,136
24				
25	<i>less</i> Utilised tax losses	–		
26	Regulatory net taxable income			24,136
27				
28	Corporate tax rate (%)	28%		
29	Regulatory tax allowance			6,758
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	109,388		
37	<i>less</i> Amortisation of initial differences in asset values	4,993		
38	<i>plus</i> Adjustment for unamortised initial differences in assets acquired	–		
39	<i>less</i> Adjustment for unamortised initial differences in assets disposed	–		
40	Closing unamortised initial differences in asset values			104,395
41				
42	Opening weighted average remaining useful life of relevant assets (years)			22
43				

Company Name **Aurora Energy Ltd**
For Year Ended **31 March 2016**

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		307,936	
47				
48	Adjusted depreciation		11,425	
49	Total depreciation		12,318	
50	Amortisation of revaluations			893
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		(14,272)	
61				
62	plus Tax effect of adjusted depreciation		3,199	
63				
64	less Tax effect of tax depreciation		4,655	
65				
66	plus Tax effect of other temporary differences*		724	
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			(16,402)
77				
78	5a(vii): Disclosure of Temporary Differences			
79	<i>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).</i>			
80				
81	5a(viii): Regulatory Tax Asset Base Roll-Forward			(\$000)
82				
83	Opening sum of regulatory tax asset values		179,329	
84	less Tax depreciation		16,626	
85	plus Regulatory tax asset value of assets commissioned		32,404	
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			195,107

Company Name **Aurora Energy Ltd**
 For Year Ended **31 March 2016**

SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

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

sch ref

5b(i): Summary—Related Party Transactions

(\$000)

Total regulatory income	230
Operational expenditure	23,931
Capital expenditure	15,302
Market value of asset disposals	—
Other related party transactions	—

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

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

* include additional rows if needed

5b(iii): Related Party Transactions

Name of related party	Related party transaction type	Description of transaction	Value of transaction (\$000)	Basis for determining value
Delta Utility Services Ltd	Sales	Recovery of Service Failure Payments	230	ID clause 2.3.7(2)(c)
Dunedin city Council	Opex	Rates Expense - Dunedin Network	791	ID clause 2.3.6(1)(c)(i)
Delta Utility Services Ltd	Opex	Service Interruptions and Emergencies in accordance with Asset Management agreement and AMP	3,523	ID clause 2.3.6(1)(c)(i)
Delta Utility Services Ltd	Opex	Service Interruptions and Emergencies - repair of equipment damaged by 3rd parties	596	ID clause 2.3.6(1)(c)(i)
Delta Utility Services Ltd	Opex	On going Vegetation Management in accordance with Asset Management agreement and AMP	5,247	ID clause 2.3.6(1)(c)(i)
Delta Utility Services Ltd	Opex	Routine inspection and maintenance work in accordance with Asset Management Agreement and	5,104	ID clause 2.3.6(1)(c)(i)
Delta Utility Services Ltd	Opex	Asset replacement and renewal work in accordance with Asset Management Agreement and AMP	878	ID clause 2.3.6(1)(c)(i)
Delta Utility Services Ltd	Opex	System Operation, support and Management in accordance with Asset Management Agreement	3,743	ID clause 2.3.6(1)(c)(i)
Delta Utility Services Ltd	Opex	Business support operations in accordance with Asset Management agreement	3,142	ID clause 2.3.6(1)(c)(i)
Delta Utility Services Ltd	Opex	General management, administration and accounting services in accordance with Administration Agreement	565	ID clause 2.3.6(1)(c)(i)
Delta Utility Services Ltd	Opex	Miscellaneous work associated with processing of easements and ad-hoc advise	287	ID clause 2.3.6(1)(c)(i)
Delta Utility Services Ltd	Opex	For Lease of CPD metering Equipment	55	ID clause 2.3.6(1)(c)(i)
Delta Utility Services Ltd	Capex	Installation of New Network Equipment	11,492	IM clause 2.2.11(5)(g)
Delta Utility Services Ltd	Capex	Installation of New Network Equipment	3,810	IM clause 2.2.11(5)(f)
	[Select one]			[Select one]

* include additional rows if needed

Company Name **Aurora Energy Ltd**
 For Year Ended **31 March 2016**

SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

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

sch ref

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

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

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

Gross term credit spread differential

–

Total book value of interest bearing debt

Leverage

44%

Average opening and closing RAB values

Attribution Rate (%)

–

Term credit spread differential allowance

–

Company Name **Aurora Energy Ltd**
 For Year Ended **31 March 2016**

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

7	5d(i): Operating Cost Allocations				
8					
9					
10	Service interruptions and emergencies				
11	Directly attributable		4,155		
12	Not directly attributable				
13	Total attributable to regulated service		4,155		
14	Vegetation management				
15	Directly attributable		5,247		
16	Not directly attributable				
17	Total attributable to regulated service		5,247		
18	Routine and corrective maintenance and inspection				
19	Directly attributable		5,104		
20	Not directly attributable				
21	Total attributable to regulated service		5,104		
22	Asset replacement and renewal				
23	Directly attributable		894		
24	Not directly attributable				
25	Total attributable to regulated service		894		
26	System operations and network support				
27	Directly attributable		3,743		
28	Not directly attributable				
29	Total attributable to regulated service		3,743		
30	Business support				
31	Directly attributable		6,030		
32	Not directly attributable				
33	Total attributable to regulated service		6,030		
34					
35	Operating costs directly attributable		25,173		
36	Operating costs not directly attributable				
37	Operational expenditure		25,173		
38					

Company Name **Aurora Energy Ltd**
 For Year Ended **31 March 2016**

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

40 Pass through and recoverable costs

(\$000)

41 Pass through costs

42 Directly attributable

1,236

43 Not directly attributable

44 Total attributable to regulated service

1,236

45 Recoverable costs

46 Directly attributable

33,166

47 Not directly attributable

48 Total attributable to regulated service

33,166

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

51 Change in cost allocation 1

52 Cost category

53 Original allocator or line items

54 New allocator or line items

56 Rationale for change

(\$000)

CY-1

Current Year (CY)

Original allocation

New allocation

Difference

–

–

61 Change in cost allocation 2

62 Cost category

63 Original allocator or line items

64 New allocator or line items

66 Rationale for change

(\$000)

CY-1

Current Year (CY)

Original allocation

New allocation

Difference

–

–

70 Change in cost allocation 3

71 Cost category

72 Original allocator or line items

73 New allocator or line items

75 Rationale for change

(\$000)

CY-1

Current Year (CY)

Original allocation

New allocation

Difference

–

–

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

† include additional rows if needed

Company Name

Aurora Energy Ltd

For Year Ended

31 March 2016

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	13,414
Not directly attributable	—
Total attributable to regulated service	13,414
Subtransmission cables	
Directly attributable	9,082
Not directly attributable	—
Total attributable to regulated service	9,082
Zone substations	
Directly attributable	64,021
Not directly attributable	—
Total attributable to regulated service	64,021
Distribution and LV lines	
Directly attributable	52,400
Not directly attributable	—
Total attributable to regulated service	52,400
Distribution and LV cables	
Directly attributable	125,626
Not directly attributable	—
Total attributable to regulated service	125,626
Distribution substations and transformers	
Directly attributable	51,795
Not directly attributable	—
Total attributable to regulated service	51,795
Distribution switchgear	
Directly attributable	20,091
Not directly attributable	—
Total attributable to regulated service	20,091
Other network assets	
Directly attributable	4,236
Not directly attributable	—
Total attributable to regulated service	4,236
Non-network assets	
Directly attributable	—
Not directly attributable	—
Total attributable to regulated service	—
Regulated service asset value directly attributable	340,665
Regulated service asset value not directly attributable	—
Total closing RAB value	340,665

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				
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				
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 component

† include additional rows if needed

Company Name	Aurora Energy Ltd
For Year Ended	31 March 2016

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		10,553
9	System growth		8,980
10	Asset replacement and renewal		5,511
11	Asset relocations		2,067
12	Reliability, safety and environment:		
13	Quality of supply	1,678	
14	Legislative and regulatory	-	
15	Other reliability, safety and environment	251	
16	Total reliability, safety and environment		1,929
17	Expenditure on network assets		29,040
18	Expenditure on non-network assets		-
19			
20	Expenditure on assets		29,040
21	plus Cost of financing		
22	less Value of capital contributions		6,114
23	plus Value of vested assets		
24			
25	Capital expenditure		22,926
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]	10,553	
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		10,553
39			
40	less Capital contributions funding consumer connection expenditure	5,059	
41	Consumer connection less capital contributions		5,494
42	6a(iv): System Growth and Asset Replacement and Renewal		
43			
44			
45	Subtransmission	495	114
46	Zone substations	6,595	383
47	Distribution and LV lines	406	3,806
48	Distribution and LV cables	910	341
49	Distribution substations and transformers	168	557
50	Distribution switchgear	232	147
51	Other network assets	174	163
52	System growth and asset replacement and renewal expenditure	8,980	5,511
53	less Capital contributions funding system growth and asset replacement and renewal	22	26
54	System growth and asset replacement and renewal less capital contributions	8,958	5,485
55			
56	6a(v): Asset Relocations		
57	Project or programme*	(\$000)	(\$000)
58	CFR 7270 5 Mile Retail Centre	564	
59	CFR 7524 Telecom Change Over	222	
60	CFR 7120 NZTA Caversham SH1 Lookout Pt Switchgear Replacement	171	
61	CFR 7684 Roundabout diversion stalker road SH6 & lower Shotover	126	
62	CFR 7961 Telecom Changeover	102	
63	* include additional rows if needed		
64	All other projects or programmes - asset relocations	882	
65	Asset relocations expenditure		2,067
66	less Capital contributions funding asset relocations	1,002	
67	Asset relocations less capital contributions		1,065

Company Name **Aurora Energy Ltd**
For Year Ended **31 March 2016**

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

68					
69	6a(vi): Quality of Supply				
70	<i>Project or programme*</i>		(\$000)	(\$000)	
71	CFR 6717 Port Chalmers Zone Sub 33kv CB Upgrade		279		
72	CFR 7229 Port Chalmers Zone Sub 33kv CB Upgrade		223		
73	CFR 7330 Backup Control Room (scada)		191		
74	CFR 7289 Supply & instalation of 6 Reclosers		157		
75	CFR 7266 Supply of 6 Reclosers		133		
76	<i>* include additional rows if needed</i>				
77	All other projects programmes - quality of supply		695		
78	Quality of supply expenditure			1,678	
79	less Capital contributions funding quality of supply		-		
80	Quality of supply less capital contributions			1,678	
81	6a(vii): Legislative and Regulatory				
82	<i>Project or programme*</i>		(\$000)	(\$000)	
83	N/A				
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	<i>* include additional rows if needed</i>				
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	<i>Project or programme*</i>		(\$000)	(\$000)	
95	CFR 7152 Replace 300KVa GM sub Serpentine avenue		59		
96	CFR 7971 Remove and relocate Poolburn regulators		47		
97	CFR 7475 Relocation HV Feeders Burnside		38		
98	CFR 8112 Transfer load from Runciman St to Main South Road		34		
99	[Description of material project or programme]				
100	<i>* include additional rows if needed</i>				
101	All other projects or programmes - other reliability, safety and environment		73		
102	Other reliability, safety and environment expenditure			251	
103	less Capital contributions funding other reliability, safety and environment		5		
104	Other reliability, safety and environment less capital contributions			246	
105					
106	6a(ix): Non-Network Assets				
107	Routine expenditure				
108	<i>Project or programme*</i>		(\$000)	(\$000)	
109	N/A				
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	<i>* include additional rows if needed</i>				
115	All other projects or programmes - routine expenditure				
116	Routine expenditure			-	
117	Atypical expenditure				
118	<i>Project or programme*</i>		(\$000)	(\$000)	
119	N/A				
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	<i>* include additional rows if needed</i>				
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 2016

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

		(\$000)	(\$000)
7	6b(i): Operational Expenditure		
8	Service interruptions and emergencies	4,155	
9	Vegetation management	5,247	
10	Routine and corrective maintenance and inspection	5,104	
11	Asset replacement and renewal	894	
12	Network opex		15,400
13	System operations and network support	3,743	
14	Business support	6,030	
15	Non-network opex		9,773
16			
17	Operational expenditure		25,173
18	6b(ii): Subcomponents of Operational Expenditure (where known)		
19	Energy efficiency and demand side management, reduction of energy losses		—
20	Direct billing*		—
21	Research and development		—
22	Insurance		223
23	* Direct billing expenditure by suppliers that directly bill the majority of their consumers		

Company Name **Aurora Energy Ltd**
 For Year Ended **31 March 2016**

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	87,711	91,267	4%
9	7(ii): Expenditure on Assets	Forecast (\$000) ²	Actual (\$000)	% variance
10	Consumer connection	5,559	10,553	90%
11	System growth	12,247	8,980	(27%)
12	Asset replacement and renewal	18,790	5,511	(71%)
13	Asset relocations	556	2,067	272%
14	Reliability, safety and environment:			
15	Quality of supply	1,187	1,678	41%
16	Legislative and regulatory	–	–	–
17	Other reliability, safety and environment	690	251	(64%)
18	Total reliability, safety and environment	1,877	1,929	3%
19	Expenditure on network assets	39,029	29,040	(26%)
20	Expenditure on non-network assets	–	–	–
21	Expenditure on assets	39,029	29,040	(26%)
22	7(iii): Operational Expenditure			
23	Service interruptions and emergencies	3,156	4,155	32%
24	Vegetation management	4,333	5,247	21%
25	Routine and corrective maintenance and inspection	5,589	5,104	(9%)
26	Asset replacement and renewal	424	894	111%
27	Network opex	13,502	15,400	14%
28	System operations and network support	3,950	3,743	(5%)
29	Business support	2,928	6,030	106%
30	Non-network opex	6,878	9,773	42%
31	Operational expenditure	20,380	25,173	24%
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	–	–	–
39	Direct billing	–	–	–
40	Research and development	–	–	–
41	Insurance	223	–	–
42				
43	<i>1 From the nominal dollar target revenue for the disclosure year disclosed under clause 2.4.3(3) of this determination</i>			
44	<i>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)</i>			

Company Name **Aurora Energy Ltd**
 For Year Ended **31 March 2016**
 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(i): Billed Quantities by Price Component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)
Standard Domestic	Standard domestic	Standard	72,038	590,939
Load Group 0	other	Standard	337	28
Load Group 0A	other	Standard	492	788
Load Group 1A	other	Standard	802	2,562
Load Group 1	other	Standard	5,672	45,037
Load Group 2	other	Standard	6,097	277,091
Load Group 2	other	Non-standard	3	169
Load Group 3	other	Standard	203	54,716
Load Group 3	other	Non-standard	2	685
Load Group 3A	other	Standard	163	85,163
Load Group 3A	other	Non-standard	2	1,818
Load Group 4	other	Standard	122	162,657
Load Group 4	other	Non-standard	1	3,461
Load Group 5	other	Standard	8	62,050
Load Group 5	other	Non-standard	1	6,056
Street Lighting	other	Standard	11	10,228
DUML, excl Street Lighting	other	Standard	2	2
Distributed Generation (Large)	other	Non-standard	10	N/A
Add extra rows for additional consumer groups or price category codes as necessary				
Standard consumer totals			85,947	1,291,261
Non-standard consumer totals			19	12,188
Total for all consumers			85,966	1,303,450

Billed quantities by price component

Price component

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

Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Period Demand (Distribution)	Transformer Lease Other Charges & Rebates (Distribution)	Fixed (Pass-through)	Energy Delivery (Pass-through)	Capacity (Pass-through)	Control Period Demand (Pass-through)
LS	Lamp	kWh	kVA	kVA x km	kW	kVA	LS	kWh	kVA	kW
72,038		590,938.968					72,038	590,938.968		
337			337				337		337	
492			978				492		978	
802			6,416			768	802		6,416	768
5,672			85,080		13,031		5,672		85,080	13,031
6,097			306,055		44,209	(6)	6,097		306,055	44,209
3			220				3		220	
203			38,963	622.907	9,146		203		38,963	9,146
2			800	19,452		(280)	2		800	
163			49,542	610,545	13,351	(93)	163		49,542	13,351
2			800	19,452		(280)	2		800	
122			87,557	1,098,514	24,781	72,516	122		87,557	24,781
1							1			
8			27,085	242,895	6,926	8,871	8		27,085	6,926
1							1			
11	11	2,878.937					11	2,878.937		
2		1,988					2	1,988		
3										
85,947	11	593,819,893	602,013	2,574,861	112,212	81,288	85,947	593,819,893	602,013	112,212
12	-	-	1,820	38,904	-	(560)	9	-	1,820	-
85,959	11	593,819,893	603,833	2,613,765	112,212	80,728	85,956	593,819,893	603,833	112,212

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

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

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)
Standard Domestic	Standard domestic	Standard	\$52,674	
Load Group 0	other	Standard	\$75	
Load Group 0A	other	Standard	\$233	
Load Group 1A	other	Standard	\$361	
Load Group 1	other	Standard	\$5,006	
Load Group 2	other	Standard	\$15,569	
Load Group 2	other	Non-standard	\$6	
Load Group 3	other	Standard	\$3,223	
Load Group 3	other	Non-standard	\$12	
Load Group 3A	other	Standard	\$4,125	
Load Group 3A	other	Non-standard	\$26	
Load Group 4	other	Standard	\$7,244	
Load Group 4	other	Non-standard	\$133	
Load Group 5	other	Standard	\$1,478	
Load Group 5	other	Non-standard	\$213	
Street Lighting	other	Standard	\$627	
DUML, excl Street Lighting	other	Standard	\$0	
Distributed Generation (Large)	other	Non-standard	\$549	
Add extra rows for additional consumer groups or price category codes as necessary				
Standard consumer totals			\$90,615	-
Non-standard consumer totals			\$938	-
Total for all consumers			\$91,553	-

Total distribution line charge revenue	Total pass-through line charge revenue (if available)	Rate (eg, \$ per day, \$ per kWh, etc.)
\$34,826	\$17,848	
\$49	\$26	
\$147	\$88	
\$9	\$56	
\$277	\$134	
\$3,021	\$1,985	
\$10,230	\$5,339	
\$5	\$0	
\$2,080	\$1,143	
\$11	\$0	
\$2,453	\$1,672	
\$25	\$1	
\$4,041	\$3,203	
\$71	\$61	
\$802	\$876	
\$83	\$130	
\$447	\$180	
\$0	\$0	
\$549		
\$58,124	\$32,491	
\$746	\$193	
\$58,869	\$32,684	

Line charge revenues (\$000) by price component

Price component

Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Period Demand (Distribution)	Transformer Lease Other Charges & Rebates (Distribution)	Fixed (Pass-through)	Energy Delivery (Pass-through)	Capacity (Pass-through)	Control Period Demand (Pass-through)
\$ / annum	\$ / lamp	\$ / kWh	\$ / kVA	\$ / kVA x km	\$ / kW	\$ / kVA	\$ / annum	\$ / kWh	\$ / kVA	\$ / kW
\$3,918		\$30,908						\$17,848		
\$49							\$26			
\$147							\$88			
\$9			\$129			\$88			\$56	\$79
\$66			\$1,531		\$1,424				\$643	\$1,343
\$141			\$5,570		\$4,525	-\$6			\$868	\$4,471
\$0			\$5		\$0				\$0	\$0
\$92			\$1,056	\$219	\$713				\$201	\$942
\$1			\$12	\$2		-\$3			\$0	
\$72			\$1,240	\$210	\$932	-\$1			\$295	\$1,376
-\$1			\$21	\$7		-\$5			\$1	
\$135			\$1,367	\$376	\$1,560	\$605			\$646	\$2,557
\$8							\$61			
\$83			\$216	\$76	\$224	\$79			\$138	\$737
\$270	\$80	\$88					\$133	\$47		
\$0		\$0						\$0		
\$549										
\$4,908	\$89	\$30,996	\$11,110	\$876	\$9,465	\$676	\$244	\$17,895	\$2,847	\$11,505
\$706	\$0	\$0	\$37	\$9	\$0	(\$7)	\$191	\$0		\$0
\$5,614	\$89	\$30,996	\$11,148	\$889	\$9,465	\$670	\$436	\$17,895	\$2,848	\$11,505

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

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end

19

Check ☒ OK

Company Name **Aurora Energy Ltd**
 For Year Ended **31 March 2016**
 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(i): Billed Quantities by Price Component

Price component	Billed quantities by price component										
	Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Period Demand (Distribution)	Transformer Lease Other Charges & Rebates (Distribution)	Fixed (Pass-through)	Energy Delivery (Pass-through)	Capacity (Pass-through)	Control Period Demand (Pass-through)
days, kW of demand, kVA, etc.)	LS	Lamp	kWh	kVA	kVA x km	kW	kVA	LS	kWh	kVA	kW
	47,496		397,220.512					47,496	397,220.512		
	122			122				122		122	
	112			224				112		224	
	401			3,208		378		401		3,208	378
	3,039			45,585		7,126		3,039		45,585	7,126
	3,046			154,183		23,972	(4)	3,046		154,183	23,972
	105			20,597	113,514	5,875		105		20,597	5,875
	88			27,338	147,189	8,757	(99)	88		27,338	8,757
	75			56,715	315,786	16,543	47,070	75		56,715	16,543
	7			25,627	156,401	6,908	8,871	7		25,627	6,908
	2							2			
	2							2			
	1										
	54,495	—	397,220.512	333,599	732,890	69,559	55,842	54,495	397,220.512	333,599	69,559
	1	—	—	—	—	—	—	—	—	—	—
	54,496	—	397,220.512	333,599	732,890	69,559	55,842	54,495	397,220.512	333,599	69,559

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

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

Price component (eg, \$ per day, \$ per kWh, etc.)	Line charge revenues (\$000) by price component										
	Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Period Demand (Distribution)	Transformer Lease Other Charges & Rebates (Distribution)	Fixed (Pass-through)	Energy Delivery (Pass-through)	Capacity (Pass-through)	Control Period Demand (Pass-through)
	\$ / annum	\$ / lamp	\$ / kWh	\$ / kVA	\$ / kVA x km	\$ / kW	\$ / kVA	\$ / annum	\$ / kWh	\$ / kVA	\$ / kW
	\$2,580		\$14,826						\$11,507		
	\$13							\$11			
	\$26							\$21			
	\$4			\$46		\$33				\$32	\$40
	\$31			\$579		\$631				\$397	\$762
	\$67			\$2,290		\$2,122	\$0			\$547	\$2,565
	\$42			\$487	\$32	\$312				\$126	\$626
	\$35			\$595	\$41	\$465	-\$1			\$167	\$933
	\$76			\$734	\$88	\$844	\$380			\$437	\$1,762
	\$7			\$189	\$44	\$223	\$79			\$136	\$736
	\$270							\$133			
	\$0		\$0					\$0	\$0		
	\$122										
	\$3,152	–	\$14,826	\$4,920	\$205	\$4,627	\$468	\$165	\$11,507	\$1,841	\$7,424
	\$122	–			–						
	\$3,274	–	\$14,826	\$4,920	\$205	\$4,627	\$468	\$165	\$11,507	\$1,841	\$7,424

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

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end

Check ☒ OK

Company Name	Aurora Energy Ltd
For Year Ended	31 March 2016
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(i): Billed Quantities by Price Component

Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)					Billed quantities by price component										
					Price component										
					Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Period Demand (Distribution)	Transformer Lease Other Charges & Rebates (Distribution)	Fixed (Pass-through)	Energy Delivery (Pass-through)	Capacity (Pass-through)	Control Period Demand (Pass-through)
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)	LS	Lamp	kWh	kVA	kVA x km	kW	kVA	LS	kWh	kVA	kW
Standard Domestic	Standard domestic	Standard	24,449	193,118	24,449		193,117,850					24,449	193,117,850		
Load Group 0	other	Standard	215	24	215			215				215		215	
Load Group 0A	other	Standard	377	692	377			754				377		754	
Load Group 1A	other	Standard	400	1,374	400			3,200		389		400		3,200	389
Load Group 1	other	Standard	2,633	20,932	2,633		39,495			5,905		2,633		39,495	5,905
Load Group 2	other	Standard	3,049	132,092	3,049		151,807			20,231		3,049		151,807	20,231
Load Group 2	other	Non-standard	3	169	3		220					3		220	
Load Group 3	other	Standard	98	21,953	98		18,366	509,393		3,271		98		18,366	3,271
Load Group 3	other	Non-standard	2	685	2		400	5,170			(280)	2		400	
Load Group 3A	other	Standard	75	32,245	75		22,204	463,356	4,594			75		22,204	4,594
Load Group 3A	other	Non-standard	2	1,818	2		800	19,452			(280)	2		800	
Load Group 4	other	Standard	47	55,540	47		30,842	782,728	8,238		25,446	47		30,842	8,238
Load Group 4	other	Non-standard	1	3,461	1							1			
Load Group 5	other	Standard	1	7,025	1		1,458	86,494		18		1		1,458	18
Load Group 5	other	Non-standard	1	6,056	1							1			
Street Lighting	other	Standard	8	2,877	8	6,466	2,876,681					8	2,876,681		
DuMIL, excl Street Lighting	other	Standard													
Distributed Generation (Large)	other	Non-standard	9	N/A	2										
Add extra rows for additional consumer groups or price category codes as necessary															
Standard consumer totals			31,352	467,872	31,352	6,466	195,994,531	268,341	1,841,971	42,646	25,446	31,352	195,994,531	268,341	42,646
Non-standard consumer totals			9	12,188	9	—	—	1,420	24,622	—	(560)	9	—	1,420	—
Total for all consumers			31,361	480,060	31,361	6,466	195,994,531	269,761	1,866,593	42,646	24,886	31,361	195,994,531	269,761	42,646

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

						Line charge revenues (\$000) by price component											Add extra columns for additional line charge revenues by price component as necessary	
Price component						Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Period Demand (Distribution)	Transformer Lease Other Charges & Rebates (Distribution)	Fixed (Pass-through)	Energy Delivery (Pass-through)	Capacity (Pass- through)	Control Period Demand (Pass-through)		
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	Rate (eg, \$ per day, \$ per kWh, etc.)	\$ / annum	\$ / lamp	\$ / kWh	\$ / kVA	\$ / kVA x km	\$ / kW	\$ / kVA	\$ / annum	\$ / kWh	\$ / kVA		\$ / kW
Standard Domestic	Standard domestic	Standard	\$23,689		\$17,370	\$6,319	\$1,333		\$16,037						\$6,319			
Load Group 0	other	Standard	\$51		\$36	\$15								\$15				
Load Group 0A	other	Standard	\$185		\$121	\$64								\$64				
Load Group 1A	other	Standard	\$205		\$143	\$23	\$5			\$83		\$55				\$23	\$38	
Load Group 1	other	Standard	\$2,606		\$1,780	\$826	\$34			\$952		\$793				\$246	\$580	
Load Group 2	other	Standard	\$7,975		\$5,750	\$2,226	\$74			\$3,279		\$2,402	-\$6			\$321	\$1,905	
Load Group 2	other	Non-standard	\$6		\$5	\$0	\$0			\$5		\$0				\$0	\$0	
Load Group 3	other	Standard	\$1,599		\$1,208	\$391	\$50			\$569	\$187	\$401				\$75	\$316	
Load Group 3	other	Non-standard	\$12		\$11	\$0	\$1			\$12	\$2		-\$3			\$0		
Load Group 3A	other	Standard	\$1,890		\$1,818	\$572	\$37			\$646	\$169	\$467				\$129	\$444	
Load Group 3A	other	Non-standard	\$26		\$25	\$0	\$1			\$21	\$7		-\$5			\$1		
Load Group 4	other	Standard	\$2,913		\$1,908	\$1,005	\$59			\$1,908	\$632	\$282	\$716	\$215		\$210	\$795	
Load Group 4	other	Non-standard	\$133		\$71	\$61	\$71								\$61			
Load Group 5	other	Standard	\$66		\$62	\$4	\$1			\$27	\$32	\$2					\$2	
Load Group 5	other	Non-standard	\$213		\$83	\$130	\$83								\$130			
Street Lighting	other	Standard	\$221		\$175	\$47												
DUML, excl Street Lighting	other	Standard	–		\$0	\$0		\$88	\$87						\$47			
Contributed Generation (Large)	other	Non-standard	\$427		\$427	\$0	\$427											
Add extra rows for additional consumer groups or price category codes as necessary																		
Standard consumer totals			\$41,401	–	\$29,870	\$11,531	\$1,750	\$88	\$16,123	\$6,189	\$674	\$4,837	\$209	\$79	\$6,366	\$1,006	\$4,080	
Non-standard consumer totals			\$816	–	\$623	\$193	\$584	–	–	\$37	\$9	\$0	(\$7)	\$191	–	\$1	\$0	
Total for all consumers			\$42,217	–	\$30,493	\$11,724	\$2,334	\$88	\$16,123	\$6,226	\$683	\$4,837	\$202	\$271	\$6,366	\$1,007	\$4,080	

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end

18

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Company Name **Aurora Energy Ltd**For Year Ended **31 March 2016**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

					Items at start of	Items at end of	Net change	Data accuracy
	Voltage	Asset category	Asset class	Units	year (quantity)	year (quantity)		(1-4)
8	All	Overhead Line	Concrete poles / steel structure	No.	21,775	22,290	515	4
9	All	Overhead Line	Wood poles	No.	32,349	31,757	(592)	4
10	All	Overhead Line	Other pole types	No.	—	—	—	N/A
11	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	526	526	—	4
12	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	—	—	—	N/A
13	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	20	21	1	4
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	25	25	—	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	36	36	—	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	11	11	—	4
17	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	—	—	—	N/A
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	—	—	—	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	—	—	—	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	—	—	—	N/A
21	HV	Subtransmission Cable	Subtransmission submarine cable	km	—	—	—	N/A
22	HV	Zone substation Buildings	Zone substations up to 66kV	No.	29	30	1	4
23	HV	Zone substation Buildings	Zone substations 110kV+	No.	—	—	—	N/A
24	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	—	—	—	N/A
25	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	5	5	—	4
26	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	—	—	—	N/A
27	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	236	238	2	4
28	HV	Zone substation switchgear	33kV RMU	No.	—	—	—	N/A
29	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	6	6	—	4
30	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	53	53	—	4
31	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	349	351	2	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	15	17	2	4
33	HV	Zone Substation Transformer	Zone Substation Transformers	No.	67	67	—	4
34	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2,308	2,307	(1)	4
35	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	—	—	—	N/A
36	HV	Distribution Line	SWER conductor	km	9	9	—	4
37	HV	Distribution Cable	Distribution UG XLPE or PVC	km	526	564	38	4
38	HV	Distribution Cable	Distribution UG PILC	km	429	429	—	4
39	HV	Distribution Cable	Distribution Submarine Cable	km	1	1	—	4
40	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	40	37	(3)	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	9	6	(3)	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	6,425	6,482	57	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	975	985	10	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	545	573	28	4
45	HV	Distribution Transformer	Pole Mounted Transformer	No.	4,155	4,152	(3)	4
46	HV	Distribution Transformer	Ground Mounted Transformer	No.	2,670	2,759	89	4
47	HV	Distribution Transformer	Voltage regulators	No.	39	41	2	4
48	HV	Distribution Substations	Ground Mounted Substation Housing	No.	2,670	2,759	89	4
49	LV	LV Line	LV OH Conductor	km	1,050	1,049	(1)	4
50	LV	LV Cable	LV UG Cable	km	877	901	24	4
51	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	217	222	5	4
52	LV	Connections	OH/UG consumer service connections	No.	85,908	86,870	962	4
53	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	477	475	(2)	4
54	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	97	98	1	4
55	All	Capacitor Banks	Capacitors including controls	No	3	3	—	4
56	All	Load Control	Centralised plant	Lot	6	6	—	4
57	All	Load Control	Relays	No	2,206	2,212	6	4
58	All	Civils	Cable Tunnels	km	—	—	—	N/A

Company Name **Aurora Energy Ltd**
For Year Ended **31 March 2016**
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

					Items at start of	Items at end of	Net change	Data accuracy
				Units	year (quantity)	year (quantity)		(1-4)
8	Voltage	Asset category	Asset class					
9	All	Overhead Line	Concrete poles / steel structure	No.	14,616	14,881	265	4
10	All	Overhead Line	Wood poles	No.	14,849	14,542	(307)	4
11	All	Overhead Line	Other pole types	No.	—	—	—	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	144	144	—	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	—	—	—	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	4	4	—	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	25	25	—	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	36	36	—	4
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	11	11	—	4
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.	110	111	1	4
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	—	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	262	262	—	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	—	—	—	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	35	35	—	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	731	731	—	4
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	—	—	—	N/A
37	HV	Distribution Line	SWER conductor	km	9	9	—	4
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	29	31	2	4
39	HV	Distribution Cable	Distribution UG PILC	km	281	280	(1)	4
40	HV	Distribution Cable	Distribution Submarine Cable	km	1	1	—	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	11	10	(1)	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	9	6	(3)	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	2,550	2,563	13	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	465	460	(5)	4
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	312	318	6	4
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	1,713	1,706	(7)	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	906	917	11	4
48	HV	Distribution Transformer	Voltage regulators	No.	11	11	—	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	906	917	11	4
50	LV	LV Line	LV OH Conductor	km	824	824	—	4
51	LV	LV Cable	LV UG Cable	km	251	257	6	4
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	149	154	5	4
53	LV	Connections	OH/UG consumer service connections	No.	54,689	54,912	223	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	305	301	(4)	4
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	39	39	—	4
56	All	Capacitor Banks	Capacitors including controls	No	3	3	—	4
57	All	Load Control	Centralised plant	Lot	3	3	—	4
58	All	Load Control	Relays	No	1,120	1,121	1	4
59	All	Civils	Cable Tunnels	km	—	—	—	N/A

Company Name **Aurora Energy Ltd**For Year Ended **31 March 2016**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

					Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1-4)
	Voltage	Asset category	Asset class	Units				
8	All	Overhead Line	Concrete poles / steel structure	No.	7,159	7,409	250	4
9	All	Overhead Line	Wood poles	No.	17,500	17,215	(285)	4
10	All	Overhead Line	Other pole types	No.	—	—	—	N/A
11	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	382	382	—	4
12	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	—	—	—	N/A
13	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	16	17	1	4
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	—	—	—	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	—	—	—	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	—	—	—	4
17	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	—	—	—	N/A
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	—	—	—	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	—	—	—	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	—	—	—	N/A
21	HV	Subtransmission Cable	Subtransmission submarine cable	km	—	—	—	N/A
22	HV	Zone substation Buildings	Zone substations up to 66kV	No.	11	12	1	4
23	HV	Zone substation Buildings	Zone substations 110kV+	No.	—	—	—	N/A
24	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	—	—	—	N/A
25	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	5	5	—	4
26	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	—	—	—	N/A
27	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	126	127	1	4
28	HV	Zone substation switchgear	33kV RMU	No.	—	—	—	N/A
29	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	6	6	—	4
30	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	30	30	—	4
31	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	87	89	2	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	15	17	2	4
33	HV	Zone Substation Transformer	Zone Substation Transformers	No.	32	32	—	4
34	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1,577	1,576	(1)	4
35	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	—	—	—	N/A
36	HV	Distribution Line	SWER conductor	km	—	—	—	4
37	HV	Distribution Cable	Distribution UG XLPE or PVC	km	495	531	36	4
38	HV	Distribution Cable	Distribution UG PILC	km	147	148	1	4
39	HV	Distribution Cable	Distribution Submarine Cable	km	—	—	—	4
40	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	29	27	(2)	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	—	—	—	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	3,875	3,919	44	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	508	523	15	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	232	253	21	4
45	HV	Distribution Transformer	Pole Mounted Transformer	No.	2,442	2,446	4	4
46	HV	Distribution Transformer	Ground Mounted Transformer	No.	1,759	1,837	78	4
47	HV	Distribution Transformer	Voltage regulators	No.	28	30	2	4
48	HV	Distribution Substations	Ground Mounted Substation Housing	No.	1,759	1,837	78	4
49	LV	LV Line	LV OH Conductor	km	226	225	(1)	4
50	LV	LV Cable	LV UG Cable	km	620	639	19	4
51	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	67	71	4	4
52	LV	Connections	OH/UG consumer service connections	No.	31,137	31,876	739	4
53	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	172	174	2	4
54	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	58	59	1	4
55	All	Capacitor Banks	Capacitors including controls	No.	—	—	—	4
56	All	Load Control	Centralised plant	Lot	3	3	—	4
57	All	Load Control	Relays	No.	1,081	1,086	5	4
58	All	Civils	Cable Tunnels	km	—	—	—	N/A

Company Name
For Year Ended
Network / Sub-network Name

Aurora Energy Ltd
31 March 2016
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.

8		Disclosure Year (year ended)		31 March 2016																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																															
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Company Name	Aurora Energy Ltd
For Year Ended	31 March 2016
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

[illegible]

Company Name	Aurora Energy Ltd
For Year Ended	31 March 2016
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

[illegible]

Company Name

Aurora Energy Ltd

For Year Ended

31 March 2016

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)
11	> 66kV	—	—
12	50kV & 66kV	108	1
13	33kV	418	92
14	SWER (all SWER voltages)	9	—
15	22kV (other than SWER)	—	—
16	6.6kV to 11kV (inclusive—other than SWER)	2,307	994
17	Low voltage (< 1kV)	1,049	901
18	Total circuit length (for supply)	3,890	1,988
19			
20	Dedicated street lighting circuit length (km)	46	176
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)		
22			
23	Overhead circuit length by terrain (at year end)	Circuit length (km)	(% of total overhead length)
24	Urban	1,172	30%
25	Rural	2,615	67%
26	Remote only	—	—
27	Rugged only	103	3%
28	Remote and rugged	—	—
29	Unallocated overhead lines	—	—
30	Total overhead length	3,890	100%
31			
32		Circuit length (km)	(% of total circuit length)
33	Length of circuit within 10km of coastline or geothermal areas (where known)	2,132	36%
34		Circuit length (km)	(% of total overhead length)
35	Overhead circuit requiring vegetation management	219	6%

Company Name

Aurora Energy Ltd

For Year Ended

31 March 2016

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)
11	> 66kV	—	—
12	50kV & 66kV	—	—
13	33kV	144	76
14	SWER (all SWER voltages)	9	—
15	22kV (other than SWER)	—	—
16	6.6kV to 11kV (inclusive—other than SWER)	731	313
17	Low voltage (< 1kV)	824	257
18	Total circuit length (for supply)	1,707	646
19			
20	Dedicated street lighting circuit length (km)	43	108
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)		
22			
23	Overhead circuit length by terrain (at year end)	Circuit length (km)	(% of total overhead length)
24	Urban	973	57%
25	Rural	721	42%
26	Remote only	—	—
27	Rugged only	14	1%
28	Remote and rugged	—	—
29	Unallocated overhead lines	—	—
30	Total overhead length	1,707	100%
31			
32		Circuit length (km)	(% of total circuit length)
33	Length of circuit within 10km of coastline or geothermal areas (where known)	2,132	91%
34		Circuit length (km)	(% of total overhead length)
35	Overhead circuit requiring vegetation management	76	4%

Company Name

Aurora Energy Ltd

For Year Ended

31 March 2016

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)
11	> 66kV	—	—
12	50kV & 66kV	108	1
13	33kV	274	16
14	SWER (all SWER voltages)	—	—
15	22kV (other than SWER)	—	—
16	6.6kV to 11kV (inclusive—other than SWER)	1,576	679
17	Low voltage (< 1kV)	225	639
18	Total circuit length (for supply)	2,183	1,334
19			
20	Dedicated street lighting circuit length (km)	3	68
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)		
22			
23	Overhead circuit length by terrain (at year end)	Circuit length (km)	(% of total overhead length)
24	Urban	199	9%
25	Rural	1,895	87%
26	Remote only	—	—
27	Rugged only	89	4%
28	Remote and rugged	—	—
29	Unallocated overhead lines	—	—
30	Total overhead length	2,183	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	143	7%

Company Name **Aurora Energy Ltd**
 For Year Ended **31 March 2016**

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

		Number of ICPs served	Line charge revenue (\$000)
8	Location *		
9	Heritage Estate (Te Anau)	102	80
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 2016**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

9e(i): Consumer Connections

Number of ICPs connected in year by consumer type

Consumer types defined by EDB*

Standard Domestic

Load Group 0

Load Group 0A

Load Group 1A

Load Group 1

Load Group 2

Load Group 3

Load Group 3A

Load Group 4

Load Group 5

Street Lighting

Distributed Unmetered Load (excl. Street Lighting)

* include additional rows if needed

Connections total

Number of
connections (ICPs)

673

(17)

82

30

(16)

73

11

8

1

845

Distributed generation

Number of connections made in year

131

connections

Capacity of distributed generation installed in year

0.46

MVA

9e(ii): System DemandDemand at time
of maximum
coincident
demand (MW)**Maximum coincident system demand**

GXP demand

248

plus Distributed generation output at HV and above

43

Maximum coincident system demand

291

less Net transfers to (from) other EDBs at HV and above

(0)

Demand on system for supply to consumers' connection points

291

Electricity volumes carried

Energy (GWh)

Electricity supplied from GXPs

1,101

less Electricity exports to GXPs

36

plus Electricity supplied from distributed generation

323

less Net electricity supplied to (from) other EDBs

(1)

Electricity entering system for supply to consumers' connection points

1,388

less Total energy delivered to ICPs

1,303

Electricity losses (loss ratio)

85

6.1%

Load factor

0.54

9e(iii): Transformer Capacity

(MVA)

Distribution transformer capacity (EDB owned)

874

Distribution transformer capacity (Non-EDB owned, estimated)

73

Total distribution transformer capacity

947

Zone substation transformer capacity

906

Company Name **Aurora Energy Ltd**For Year Ended **31 March 2016**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

9e(i): Consumer Connections

Number of ICPs connected in year by consumer type

Consumer types defined by EDB*

Standard Domestic

Load Group 0

Load Group 0A

Load Group 1A

Load Group 1

Load Group 2

Load Group 3

Load Group 3A

Load Group 4

Load Group 5

Street Lighting

Distributed Unmetered Load (excl. Street Lighting)

* include additional rows if needed

Connections total

Number of
connections (ICPs)

120

(15)

18

(3)

(30)

2

6

4

(5)

97

Distributed generation

Number of connections made in year

47

connections

Capacity of distributed generation installed in year

0.15

MVA

9e(ii): System Demand**Maximum coincident system demand**

GXP demand

175

plus Distributed generation output at HV and above

22

Maximum coincident system demand

197

less Net transfers to (from) other EDBs at HV and above

Demand on system for supply to consumers' connection points

197

Electricity volumes carried

Electricity supplied from GXPs

706

less Electricity exports to GXPs

3

plus Electricity supplied from distributed generation

165

less Net electricity supplied to (from) other EDBs

-

Electricity entering system for supply to consumers' connection points

867

less Total energy delivered to ICPs

1,303

Electricity losses (loss ratio)

(436)

(50.3%)

Load factor

0.50

9e(iii): Transformer Capacity

(MVA)

Distribution transformer capacity (EDB owned)

485

Distribution transformer capacity (Non-EDB owned, estimated)

49

Total distribution transformer capacity

534

Zone substation transformer capacity

610

Company Name

Aurora Energy Ltd

For Year Ended

31 March 2016

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

Consumer types defined by EDB*

Number of
connections (ICPs)

Standard Domestic

550

Load Group 0

(2)

Load Group 0A

64

Load Group 1A

33

Load Group 1

14

Load Group 2

71

Load Group 3

5

Load Group 3A

4

Load Group 4

5

Load Group 5

1

Street Lighting

Distributed Unmetered Load (excl. Street Lighting)

* include additional rows if needed

Connections total

745

Distributed generation

Number of connections made in year

84

connections

Capacity of distributed generation installed in year

0.32

MVA

9e(ii): System Demand**Maximum coincident system demand**

GXP demand

84

plus Distributed generation output at HV and above

22

Maximum coincident system demand

107

less Net transfers to (from) other EDBs at HV and above

-

Demand on system for supply to consumers' connection points

107

Electricity volumes carried

Electricity supplied from GXPs

395

less Electricity exports to GXPs

33

plus Electricity supplied from distributed generation

158

less Net electricity supplied to (from) other EDBs

-

Electricity entering system for supply to consumers' connection points

520

less Total energy delivered to ICPs

1,303

Electricity losses (loss ratio)

(784)

(150.7%)

Load factor

0.56

9e(iii): Transformer Capacity

(MVA)

Distribution transformer capacity (EDB owned)

388

Distribution transformer capacity (Non-EDB owned, estimated)

24

Total distribution transformer capacity

413

Zone substation transformer capacity

296

Company Name **Aurora Energy Ltd**For Year Ended **31 March 2016**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

10(i): Interruptions**Interruptions by class****Number of interruptions**

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

293
563
1
857

Total**Interruption restoration****≤3Hrs >3hrs**

Class C interruptions restored within

365	198
-----	-----

SAIFI and SAIDI by class**SAIFI SAIDI**

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

0.23	36.3
2.02	202.9
0.13	4.4
2.38	243.5

Total**Normalised SAIFI and SAIDI****Normalised SAIFI Normalised SAIDI**

Classes B & C (interruptions on the network)

1.74	128.7
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Quality path normalised reliability limit**SAIFI reliability limit SAIDI reliability limit**

SAIFI and SAIDI limits applicable to disclosure year*

1.45	83.4
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* not applicable to exempt EDBs

Company Name **Aurora Energy Ltd**For Year Ended **31 March 2016**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.

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

Lightning	0.05	5.7
Vegetation	0.24	36.5
Adverse weather	0.42	86.1
Adverse environment	0.02	1.8
Third party interference	0.10	8.5
Wildlife	0.03	3.5
Human error	0.08	0.9
Defective equipment	0.55	36.6
Cause unknown	0.52	23.3

10(iii): Class B Interruptions and Duration by Main Equipment Involved**Main equipment involved****SAIFI****SAIDI**

Subtransmission lines		
Subtransmission cables	0.00	0.0
Subtransmission other		
Distribution lines (excluding LV)	0.18	26.2
Distribution cables (excluding LV)	0.01	4.9
Distribution other (excluding LV)	0.04	5.1

10(iv): Class C Interruptions and Duration by Main Equipment Involved**Main equipment involved****SAIFI****SAIDI**

Subtransmission lines	0.02	1.3
Subtransmission cables		
Subtransmission other	0.08	3.5
Distribution lines (excluding LV)	1.52	174.3
Distribution cables (excluding LV)	0.06	4.0
Distribution other (excluding LV)	0.34	19.9

10(v): Fault Rate**Main equipment involved****Number of Faults****Circuit length (km)****Fault rate (faults per 100km)**

Subtransmission lines	41	526	7.79
Subtransmission cables		93	—
Subtransmission other	7		
Distribution lines (excluding LV)	398	2,315	17.19
Distribution cables (excluding LV)	28	994	2.82
Distribution other (excluding LV)	181		
Total	655		

Company Name	Aurora Energy Ltd
For Year Ended	31 March 2016
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

10(i): Interruptions**Interruptions by class****Number of interruptions**

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

55
203
1
259

Total**Interruption restoration**

≤3Hrs >3hrs

Class C interruptions restored within

108	95
-----	----

SAIFI and SAIDI by class

SAIFI SAIDI

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

0.14	13.2
1.18	146.7
0.21	6.9
1.53	166.7

Total**Normalised SAIFI and SAIDI**

Normalised SAIFI Normalised SAIDI

Classes B & C (interruptions on the network)

N/A	N/A
-----	-----

Quality path normalised reliability limit

SAIFI reliability limit SAIDI reliability limit

SAIFI and SAIDI limits applicable to disclosure year*

N/A	N/A
-----	-----

* not applicable to exempt EDBs

Company Name	Aurora Energy Ltd
For Year Ended	31 March 2016
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	0.07	7.2
Vegetation	0.16	15.8
Adverse weather	0.26	86.2
Adverse environment	0.02	2.8
Third party interference	0.05	5.6
Wildlife	0.02	2.7
Human error	0.04	0.4
Defective equipment	0.41	18.8
Cause unknown	0.15	7.1

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)	0.12	10.4
Distribution cables (excluding LV)	0.00	0.2
Distribution other (excluding LV)	0.02	2.5

10(iv): Class C Interruptions and Duration by Main Equipment Involved**Main equipment involved****SAIFI****SAIDI**

Subtransmission lines	0.02	1.6
Subtransmission cables		
Subtransmission other	0.10	2.7
Distribution lines (excluding LV)	0.68	119.6
Distribution cables (excluding LV)	0.08	3.3
Distribution other (excluding LV)	0.30	19.4

10(v): Fault Rate**Main equipment involved****Number of Faults****Circuit length (km)****Fault rate (faults per 100km)**

Subtransmission lines	11	144	7.64
Subtransmission cables	–	76	–
Subtransmission other	3		
Distribution lines (excluding LV)	116	740	15.68
Distribution cables (excluding LV)	15	313	4.79
Distribution other (excluding LV)	72		
Total	217		

Company Name **Aurora Energy Ltd**For Year Ended **31 March 2016**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

10(i): Interruptions**Interruptions by class****Number of interruptions**

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

238
360
598

Total**Interruption restoration**

≤3Hrs

>3hrs

Class C interruptions restored within

257	103
-----	-----

SAIFI and SAIDI by class

SAIFI

SAIDI

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

0.38	76.4
3.48	301.2
3.86	377.7

Total**Normalised SAIFI and SAIDI**

Normalised SAIFI

Normalised SAIDI

Classes B & C (interruptions on the network)

N/A	N/A
-----	-----

Quality path normalised reliability limit

SAIFI reliability limit

SAIDI reliability limit

SAIFI and SAIDI limits applicable to disclosure year*

N/A	N/A
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* not applicable to exempt EDBs

Company Name	Aurora Energy Ltd
For Year Ended	31 March 2016
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	0.03	3.2
Vegetation	0.38	72.5
Adverse weather	0.71	86.1
Adverse environment	0.00	0.2
Third party interference	0.20	13.6
Wildlife	0.04	5.0
Human error	0.16	1.7
Defective equipment	0.79	67.5
Cause unknown	1.17	51.4

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines		
Subtransmission cables	0.00	0.0
Subtransmission other		
Distribution lines (excluding LV)	0.28	53.8
Distribution cables (excluding LV)	0.03	13.1
Distribution other (excluding LV)	0.07	9.5

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.04	0.7
Subtransmission cables		
Subtransmission other	0.04	4.8
Distribution lines (excluding LV)	2.98	269.9
Distribution cables (excluding LV)	0.03	5.1
Distribution other (excluding LV)	0.40	20.8

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	30	382	7.85
Subtransmission cables		17	—
Subtransmission other	4		
Distribution lines (excluding LV)	282	1,576	17.89
Distribution cables (excluding LV)	13	679	1.91
Distribution other (excluding LV)	109		
Total	438		

Company Name	Aurora Energy Limited
For Year Ended	31 March 2016

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 2016 ROI is below the midpoint estimate of WACC. 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 \$ 1,355
- Transmission Charge Recovered \$ 1,444
- Other income incl accident damage \$ 433
- Service Failure Recoveries \$ 230

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 2016 disclosure year, related party transactions have been recorded either at :

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

The impact of these adjustments are as follows (\$000): 2016 Yr

Original Cost (and regulatory tax value)	32,404
Less offset customer contributions	(6,114)
Less margin/ indirect cost on related party capex	(6,393)
Less transaction cost of assets subject to market valuation	(4,326)
Plus assets included at valuation	4,875

Value RAB assets commissioned	20,446

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 \$2,568,000 of customer contribution that is assessable for income tax purposes in that year.

The figure 'Expenditure or loss in regulatory profit or (loss) before tax but not deductible' relates to (\$18,000) 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 \$724,000 shown in the line 'Tax effect of other temporary differences' is (in \$000):

Value of customer contributions as above	\$2,568
Plus doubtful debts as above	\$18

Sub-total of differences	\$2,586
Tax effect at 28%	\$724

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.

Operating costs no longer include the overhead component of related party capex expenditure.

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

Asset allocation (Schedule 5e)

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

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, including the value of the expenditure, the purpose of the expenditure, and the operational expenditure categories the expenditure relates to.

Box 11: Explanation of operational expenditure for the disclosure year

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

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

There are no items of operational expenditure that have been identified as atypical, however:

- expenditure on vegetation management and routine and corrective maintenance continues to remain at higher levels than in disclosure years 2013 and earlier.

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 increased development activity, mainly within the Central Otago subnetwork. Our AMP forecast a projected a down turn in subdivision and irrigation development in the Upper Clutha and Manuherikia Valley and this did not eventuate.

The variance in 'system growth' is largely attributable to the deferment of work at Omakau (partially offset by works on the Lauder flat and the Manuherikia river crossing) and Riverbank road.

'Asset replacement and renewal' expenditure is significantly below forecast. This variance is largely attributable to the deferment of Carisbrook zone substation, 33kV Carisbrook Cables, the Port Chalmers harbour crossing and a number of the SCCP relates projects.

Asset relocation activity has been greater than expected, largely driven by relocation of assets to facilitate irrigation infrastructure, and an accelerated chorus changeovers associated with the UFB rollout. 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 RY16 which included 8 separate boundary events. The major variance associated with vegetation management is a timing variance with works not performed in the final quarter of RY14/15 carried over in to the first quarter of RY15/16.

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	\$87.711 million (2015 pricing methodology)
Reported – Schedule 8 (Total Business)	\$91.553 million
Difference	\$3.842 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 to ensure that allowable notional revenue, as determined under the default price path, is not exceeded.

In the assessment period, the volume of energy delivered to standard domestic consumers (the only consumer groups with volume-based pricing) increased from the prior year (by 3.3%). Energy delivered to standard domestic consumers disclosed in 2015/16 was 590.9GWh, compared to 572.2GWh in this current disclosure (deliveries to standard domestic consumers remain behind the 605.2GWh recorded in 2012/13).

Standard domestic connection numbers also increased by 0.9%. Standard domestic connection numbers disclosed in 2014/15 were 71,670, compared to 72,038 in this current disclosure.

Accordingly, there was a material increase in the average energy use per standard domestic consumer – 8,203kWh versus 8,025kWh in 2014/15.

At the same time, increased development activity in Central Otago has seen an increase General connections that are priced predominantly on the basis of demand and capacity

Network Reliability for the Disclosure Year (Schedule 10)

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

Box 14: Commentary on network reliability for the disclosure year

In accordance with Information Disclosure definitions:

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

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 (2016), 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.

Distribution assets including distribution substations, lines and cables etc. are not currently covered due to the geographical spread, the lower value of the individual assets and the reduced likelihood of significant loss on any less than region wide event.

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 several amendments to previously disclosed information. These are:

Changes to previously disclosed Amortisation of differences in asset values, the Regulatory profit / (loss), tax calculation and revision of the Deferred Tax Balances.

1) Schedule 5a. Report on Regulatory Tax Allowance

Schedule 5a(iii) Amortisation of Initial Difference in Asset Values has been restated to exclude the previous adjustments made for amortised initial differences in assets acquired in each year, as the assets concerned were not acquired from another EDB. The attached sheet details what was originally disclosed, the annual revisions and amended carried and brought forward balances.

As a result of the removal of the annual differences above, we have also restated the opening weighted remaining useful life of the relevant assets as it relates purely to the 2010 initial difference. Refer to attached adjustment sheet.

Schedule 5a(i) Regulatory profit / (loss) before tax, has been restated to recognise the revised calculation of amortisation of initial differences in asset values. The regulatory tax calculation has also been updated and transferred into Schedule 3(i) Regulatory profit line 31. Refer to attached Adjustment sheet.

Schedule 5a(vi) Calculation of Deferred Tax Balance has been restated on line 73, to reflect the revised deferred tax effect due to:

- (a) the correction of amortisation of initial tax differences in asset values and
- (b) the removal of the deferred tax adjustment relating to differences in assets acquired during the year.

Refer to attached Adjustment sheet for details.

2) Schedule 3 Report on Regulatory Profit

Schedule 3(i) Regulatory profit has been adjusted to reflect the corrected regulatory tax allowance from Schedule 5a, and as a result the regulatory profit / (loss) figure shown in line 33 has been updated. Refer to Attached Adjustment sheet.

3) Schedule 2 Report on Return on Investment

Schedule 2(ii) Information Supporting the ROI has been restated to reflect the restated opening and closing balances for deferred tax.

Schedule 2(i) Return on Investment, there has been a minor impact upon the two ratios shown in respect of:

- (a) Post WACC
- (b) Vanilla WACC

For full details refer to attached Adjustment sheet.

B) The removal of previously expensed non capitalised indirect costs relating to the 2014 and 2015 information disclosures:

Previously expensed non capitalised indirect costs included as business support expenditure in 2015 \$1.819 million and
In 2014 \$2.026 million has now been removed, resulting in those same dollar value restatements being made to:

- 1) Schedule 6b, Report on Operational Expenditure (line 14)
Schedule 5d, Report on Cost Allocations (line 31)
Schedule 7, Comparison of Forecasts to Actual Expenditure (line 29)
Schedule 3, Report on Regulatory Profit where the amended operational expenditure amount is automatically brought through (line 15) and,
Schedule 5a, Report on Regulatory Tax Allowance, where the updated figures for regulatory profit / (loss) before tax is automatically updated (line 8).
- 2) Schedule 5a, Report on Regulatory Tax allowance is also updated for the tax effect of removing the above expenditure transactions (line 29 – Regulatory tax allowance)
The effect of this is to increase the Regulatory tax allowance by:
\$0.509 million in 2015 and
\$0.567 million in 2014
- 3) Schedule 3, Report on Regulatory Profit is further updated by the amended regulatory tax allowance figure that is automatically transferred from Schedule 5a (into line 29).
- 4) The 2014 and 2015 comparative ROI's for:
(a) Post WACC
(b) Vanilla WACC
have been restated to incorporate the above net change to the Regulatory profit / (loss).

For full details refer to attached Adjustment sheet

Company Name Aurora Energy Limited

For Year Ended 31 March 2016

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 \$(\$286,000) discrepancy between the total line charge revenue reported in schedule 8, and that recorded in Aurora's financial system. The schedule 8 information has been compiled from a monthly reconciliation model using information derived from Aurora's connection management system. As such, the model may contain contain some wash-up values recorded in the disclosure period, but attributable to events outside the disclosure period. Line charge revenue derived from Aurora's financial system includes accruals for over/under reporting by retailers, calculated with respect to published loss ratios. The variability in retailer reporting can be significant month to month. The line charge revenue stated in schedule 3 (line 9) and schedule 7 (line 8) has been manually entered and reflects the value stated in Aurora's financial system.

SCHEDULE 18

Certification for Year-end Disclosures

Clause 2.9.2

We, Ian Murray Parton and Stuart James McLauchlan, 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.



.....
Ian Murray Parton



.....
Stuart James McLauchlan

29 September 2016

AURORA ENERGY LIMITED - DETAILS OF CHANGES TO PREVIOUS INFORMATION DISCLOSURES

1) **SCHEDULE 5a (iii) - Amortisation of Initial Differences in Asset Values**

VERSION AS PREVIOUSLY DISCLOSED

	2010	2011	2012	2013	2014	2015
Opening amortised initial differences in asset values	139,582	127,085	117,616	107,833	98,434	85,833
Amortisation of initial difference in asset values	5,001	4,487	4,175	3,859	3,587	3,128
Adjustment for unamortised initial differences in assets acquired	7,496	4,864	5,509	5,540	9,013	6,804
Adjustment for unamortised initial differences in assets disposed	-	117	99	-	-	-
	<u>127,085</u>	<u>117,616</u>	<u>107,833</u>	<u>98,434</u>	<u>85,833</u>	<u>75,901</u>
Opening weighted average remaining asset life (years)	28	28	28	28	27	27

AMENDED DISCLOSURE FOLLOWING CHANGES MADE

	2010	2011	2012	2013	2014	2015	
Opening amortised initial differences in asset values	139,582	134,581	129,463	124,367	119,374	114,382	updated sch 5a row 36
Amortisation of initial difference in asset values	5,001	5,001	4,997	4,993	4,993	4,993	updated sch 5a row 37
Adjustment for unamortised initial differences in assets acquired	-	-	-	-	-	-	updated sch 5a row 38
Adjustment for unamortised initial differences in assets disposed	-	117	99	-	-	-	
	<u>134,581</u>	<u>129,463</u>	<u>124,367</u>	<u>119,374</u>	<u>114,382</u>	<u>109,389</u>	updated sch 5a row 40
Opening weighted average remaining asset life (years)	28	27	26	25	24	23	updated sch 5a row 42

2) **SCHEDULE 5a (i) - Regulatory Tax Allowance**

VERSION AS PREVIOUSLY DISCLOSED

	2010	2011	2012	2013	2014	2015
Regulatory profit / (loss) before tax			28,141	29,485	26,642	23,704
<i>plus</i> Income not included in regulatory profit / (loss) before tax but taxable			800	1,105	1,513	1,957
Expenditure or loss in regulatory profit / (loss) before tax but not deductible			137	(16)	19	(19)
Amortisation of initial differences in asset values			4,151	3,809	3,587	3,128
Amortisation of revaluations			686	652	746	915
			<u>5,774</u>	<u>5,550</u>	<u>5,865</u>	<u>5,981</u>
<i>less</i> Total revaluations			-	2,696	4,879	273
Income included in regulatory profit / (loss) before tax but not taxable			-	-	-	-
Discretionary discounts and customer rebates			-	-	-	-
Expenditure or loss deductible but not in regulatory profit / (loss) before tax			-	-	-	-
Notional deductible interest			8,655	8,392	7,516	8,766
			<u>8,655</u>	<u>11,088</u>	<u>12,395</u>	<u>9,039</u>
Regulatory taxable income			25,261	23,947	20,112	20,646
Utilised tax losses			-	-	-	-
Regulatory net taxable income			25,261	23,947	20,112	20,646
Regulatory tax allowance			7,073	6,705	5,631	5,781

AMENDED DISCLOSURE FOLLOWING CHANGES MADE

	2010	2011	2012	2013	2014	2015
Restated Regulatory profit / (loss) before tax			28,141	29,485	28,668	25,523
<i>plus</i> Income not included in regulatory profit / (loss) before tax but taxable			800	1,105	1,513	1,957
Expenditure or loss in regulatory profit / (loss) before tax but not deductible			137	(16)	19	(19)
Amortisation of initial differences in asset values			4,997	4,993	4,993	4,993
Amortisation of revaluations			686	652	746	915
			<u>6,620</u>	<u>6,734</u>	<u>7,271</u>	<u>7,846</u>
<i>less</i> Total revaluations			-	2,696	4,879	273
Income included in regulatory profit / (loss) before tax but not taxable			-	-	-	-
Discretionary discounts and customer rebates			-	-	-	-
Expenditure or loss deductible but not in regulatory profit / (loss) before tax			-	-	-	-
Notional deductible interest			8,541	8,245	7,341	8,487
			<u>8,541</u>	<u>10,941</u>	<u>12,220</u>	<u>8,760</u>
Restated Regulatory taxable income			26,219	25,278	23,719	24,609
Utilised tax losses			-	-	-	-
Restated Regulatory net taxable income			26,219	25,278	23,719	24,609
Restated Regulatory tax allowance			7,341	7,078	6,641	6,891

3) **SCHEDULE 5a (vi) - Calculation of Deferred Tax Balance**

VERSION AS PREVIOUSLY DISCLOSED

	2010	2011	2012	2013	2014	2015
Opening deferred tax		(370)	(1,434)	(2,182)	(2,683)	(1,920)
<i>plus</i> Tax effect of adjusted depreciation	3,040	3,028	2,892	2,921	3,004	3,087
<i>less</i> Tax effect of tax depreciation	4,131	4,294	4,169	4,206	4,179	4,341
<i>plus</i> Tax effect of other temporary differences*	(28)	125	185	313	419	553

<i>less</i> Tax effect of amortisation of initial differences in asset values	1,500	1,346	1,169	1,081	1,004	876
<i>plus</i> Deferred tax balance relating to assets acquired in the disclosure year	2,249	1,458	1,543	1,552	2,523	1,905
<i>less</i> Deferred tax balance relating to assets disposed in the disclosure year	-	35	30	-	-	-
<i>plus</i> Deferred tax cost allocation adjustment	-	-	-	-	-	-
Closing deferred tax	(370)	(1,434)	(2,182)	(2,683)	(1,920)	(1,592)

AMENDED DISCLOSURE FOLLOWING CHANGES MADE

	2010	2011	2012	2013	2014	2015
Opening deferred tax		(2,619)	(5,225)	(7,640)	(10,019)	(12,173)
<i>plus</i> Tax effect of adjusted depreciation	3,040	3,024	2,888	2,912	3,004	3,087
<i>less</i> Tax effect of tax depreciation	4,131	4,294	4,169	4,206	4,179	4,341
<i>plus</i> Tax effect of other temporary differences*	(28)	125	185	313	419	553
<i>less</i> Tax effect of amortisation of initial differences in asset values	1,500	1,426	1,289	1,398	1,398	1,398
<i>plus</i> Deferred tax balance relating to assets acquired in the disclosure year	-	-	-	-	-	-
<i>less</i> Deferred tax balance relating to assets disposed in the disclosure year	-	35	30	-	-	-
<i>plus</i> Deferred tax cost allocation adjustment	-	-	-	-	-	-
Closing deferred tax	(2,619)	(5,225)	(7,640)	(10,019)	(12,173)	(14,272)

4) SCHEDULE 3 Report on Regulatory Profit

VERSION AS PREVIOUSLY DISCLOSED

	2010	2011	2012	2013	2014	2015
Regulatory profit / (loss) before tax			28,141	29,485	26,642	23,704
<i>less</i> Regulatory tax allowance			7,073	6,705	5,631	5,781
Regulatory profit/(loss) including financial incentives and wash-ups			21,068	22,780	21,011	17,923

AMENDED DISCLOSURE FOLLOWING CHANGES MADE

	2010	2011	2012	2013	2014	2015
Regulatory profit / (loss) before tax as originally disclosed			28,141	29,485	26,642	23,704
Add Back previously claimed non capitalised indirect costs (in operating costs)			-	-	2,026	1,819
Restated Regulatory profit / (loss) before tax			28,141	29,485	28,668	25,523
<i>less</i> Restated Regulatory tax allowance			7,341	7,078	6,641	6,891
Restated Regulatory profit/(loss) including financial incentives and wash-ups			20,800	22,407	22,027	18,632

5) SCHEDULE 2 (ii) Information Supporting the ROI

VERSION AS PREVIOUSLY DISCLOSED

	2010	2011	2012	2013	2014	2015
Total opening RAB value	285,613	294,631	307,618	313,820	318,316	324,967
<i>plus</i> Opening deferred tax	-	(370)	(1,434)	(2,182)	(2,683)	(1,920)
Opening RIV	285,613	294,261	306,184	311,638	315,633	323,047
Line charge revenue				84,995	82,403	90,830
Expenses cash outflow				50,028	52,029	58,091
<i>add</i> Assets commissioned				12,886	13,374	17,298
<i>less</i> Asset disposals				-	129	-
<i>add</i> Tax payments				6,204	6,394	6,110
<i>less</i> Other regulated income				2,908	2,862	2,633
Mid-year net cash outflows				66,210	68,806	78,866
Term credit spread differential allowance	-	-	-	-	-	-
Total closing RAB value	294,631	307,618	313,820	318,316	324,967	330,597
<i>less</i> Adjustment resulting from asset allocation	-	-	-	-	-	-
<i>less</i> Lost and found assets adjustment	-	-	-	-	-	-
<i>plus</i> Closing deferred tax	(370)	(1,434)	(2,182)	(2,683)	(1,920)	(1,592)
Closing RIV	294,261	306,184	311,638	315,633	323,047	329,005

AMENDED DISCLOSURE FOLLOWING CHANGES MADE

	2010	2011	2012	2013	2014	2015
Total opening RAB value	285,613	294,631	307,618	313,820	318,316	324,967
<i>plus</i> Restated Opening deferred tax	-	(2,619)	(5,225)	(7,640)	(10,019)	(12,173)
Opening RIV	285,613	292,012	302,393	306,180	308,297	312,794
Line charge revenue				84,995	82,403	90,830
Restated Expenses cash outflow				50,028	50,003	56,272
<i>add</i> Assets commissioned				12,886	13,374	17,298
<i>less</i> Asset disposals				-	129	-
<i>add</i> Restated Tax payments				4,699	4,487	4,792
<i>less</i> Other regulated income				2,908	2,862	2,633

Mid-year net cash outflows				64,705	64,873	75,729
Term credit spread differential allowance	-	-	-	-	-	-
Total closing RAB value	294,631	307,618	313,820	318,316	324,967	330,597
<i>less</i> Adjustment resulting from asset allocation	-	-	-	-	-	-
<i>less</i> Lost and found assets adjustment	-	-	-	-	-	-
<i>plus</i> Closing deferred tax	(2,619)	(5,225)	(7,640)	(10,019)	(12,173)	(14,272)
Closing RIV	292,012	302,393	306,180	308,297	312,794	316,325

6) **SCHEDULE 2 (i) Return on Investment**

VERSION AS PREVIOUSLY DISCLOSED

	2010	2011	2012	2013	2014	2015
ROI – comparable to a post tax WACC						
Reflecting all revenue earned			5.98%	6.56%	5.95%	4.72%
Excluding revenue earned from financial incentives				6.56%	5.95%	4.72%
Excluding revenue earned from financial incentives and wash-ups				6.56%	5.95%	4.72%
ROI – comparable to a vanilla WACC						
Reflecting all revenue earned			6.76%	7.34%	6.64%	5.50%
Excluding revenue earned from financial incentives				7.34%	6.64%	5.50%
Excluding revenue earned from financial incentives and wash-ups				7.34%	6.64%	5.50%

AMENDED DISCLOSURE FOLLOWING CHANGES MADE

	2010	2011	2012	2013	2014	2015
ROI – comparable to a post tax WACC						
Reflecting all revenue earned			5.31%	6.59%	6.48%	5.15%
Excluding revenue earned from financial incentives				6.59%	6.48%	5.15%
Excluding revenue earned from financial incentives and wash-ups				6.59%	6.48%	5.15%
ROI – comparable to a vanilla WACC						
Reflecting all revenue earned			6.09%	7.37%	7.17%	5.94%
Excluding revenue earned from financial incentives				7.37%	7.17%	5.94%
Excluding revenue earned from financial incentives and wash-ups				7.37%	7.17%	5.94%

Independent Assurance Report

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

The Auditor-General is the auditor of Aurora Energy Limited (the company). The Auditor-General has appointed me, Scott Tobin, using the staff and resources of Audit New Zealand, to provide an opinion, on her 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 and 16 in Schedule 14 ('the Disclosure Information') for the disclosure year ended 31 March 2016, 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 issued by the External Reporting Board 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.

We also evaluated:

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

Use of this report

This independent 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 her employees, and Audit New Zealand and its employees may deal with the company on normal terms within the ordinary course of trading activities of the company. Other than any dealings on normal terms within the ordinary course of business, this engagement, the audit of the annual compliance statement under the Electricity Distribution Services Default Price-Quality Path Determination 2015, 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.



Scott Tobin
Audit New Zealand
On behalf of the Auditor-General
Dunedin, New Zealand
29 September 2016