For the disclosure year ending 31 March 2023

INFORMATION DISCLOSURE

Aurora ENERGY

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Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**

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 this ID determination. This will include information disclosed in accordance with this and other schedules, and information disclosed under the other requirements of this determination.

This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

1(i): Expenditure metrics

	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)
Operational expenditure	35,615	512	156,376	7,716	50,442
Network	15,224	219	66,841	3,298	21,561
Non-network	20,392	293	89,534	4,418	28,881
Expenditure on assets	71,683	1,030	314,738	15,530	101,525
Network	69,665	1,001	305,878	15,093	98,667
Non-network	2,018	29	8,860	437	2,858

1(ii): Revenue metrics

	Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
Total consumer line charge revenue	90,865	1,306
Standard consumer line charge revenue	81,918	1,169
Non-standard consumer line charge revenue	1,352,525	907,572

1(iii): Service intensity measures

Demand density	49	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
Volume density	217	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
Connection point density	15	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
Energy intensity	14,369	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*

1(iv): Composition of regulatory income

	($000)	% of revenue
Operational expenditure	48,271	39.77%
Pass-through and recoverable costs excluding financial incentives and wash-ups	29,931	24.66%
Total depreciation	25,779	21.24%
Total revaluations	42,563	35.07%
Regulatory tax allowance	4,066	3.35%
Regulatory profit/(loss) including financial incentives and wash-ups	55,890	46.05%
Total regulatory income	121,374	

1(v): Reliability

Interruption rate	30.67	*Interruptions per 100 circuit km*

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

This schedule requires information on the Return on Investment (ROI) for the EDB relative to the Commerce Commission's estimates of post tax WACC and vanilla WACC. EDBs must calculate their ROI based on a monthly basis if required by clause 2.3.3 of this 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).

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sch ref

2(i): Return on Investment

	CY-2	CY-1	Current Year CY
ROI – comparable to a post tax WACC	%	%	%
Reflecting all revenue earned	1.46%	6.98%	8.19%
Excluding revenue earned from financial incentives	4.30%	9.33%	6.87%
Excluding revenue earned from financial incentives and wash-ups	4.30%	9.33%	6.96%
Mid-point estimate of post tax WACC	3.72%	3.52%	4.88%
25th percentile estimate	3.04%	2.84%	4.20%
75th percentile estimate	4.40%	4.20%	5.56%
ROI – comparable to a vanilla WACC			
Reflecting all revenue earned	1.79%	7.27%	8.71%
Excluding revenue earned from financial incentives	4.63%	9.63%	7.38%
Excluding revenue earned from financial incentives and wash-ups	4.63%	9.63%	7.47%
WACC rate used to set regulatory price path	4.57%	4.57%	4.57%
Mid-point estimate of vanilla WACC	4.05%	3.82%	5.39%
25th percentile estimate	3.37%	3.14%	4.71%
75th percentile estimate	4.73%	4.50%	6.07%

2(ii): Information Supporting the ROI

			($000)	
	Total opening RAB value	645,301		
plus	Opening deferred tax	(30,287)		
Opening RIV			615,014	
Line charge revenue			123,153	
	Expenses cash outflow	78,202		
add	Assets commissioned	76,873		
less	Asset disposals	2,871		
add	Tax payments	904		
less	Other regulated income	(1,779)		
Mid-year net cash outflows			154,886	
Term credit spread differential allowance			–	
	Total closing RAB value	736,088		
less	Adjustment resulting from asset allocation	0		
less	Lost and found assets adjustment	–		
plus	Closing deferred tax	(33,450)		
Closing RIV			702,638	
ROI – comparable to a vanilla WACC				8.71%
	Leverage (%)			42%
	Cost of debt assumption (%)			4.38%
	Corporate tax rate (%)			28%
ROI – comparable to a post tax WACC				8.19%

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

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EDBs must provide explanatory comment on their ROI in Schedule 14 (Mandatory Explanatory Notes).

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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	6.91%
Year-end ROI – comparable to a post tax WACC	6.40%

** 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	11,508	
Purchased assets – avoided transmission charge	–	
Energy efficiency and demand incentive allowance		
Quality incentive adjustment	(12)	
Other financial incentives	–	
Financial incentives		11,496
Impact of financial incentives on ROI		1.32%
Input methodology claw-back	–	
CPP application recoverable costs	–	
Catastrophic event allowance	–	
Capex wash-up adjustment	(785)	
Transmission asset wash-up adjustment	–	
2013–15 NPV wash-up allowance	–	
Reconsideration event allowance	–	
Other wash-ups	–	
Wash-up costs		(785)
Impact of wash-up costs on ROI		–0.09%

Company Name	**Aurora Energy Limited**
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SCHEDULE 3: REPORT ON REGULATORY PROFIT

This schedule requires information on the calculation of regulatory profit for the EDB for the disclosure year. All EDBs must complete all sections and provide explanatory comment on their regulatory profit in Schedule 14 (Mandatory Explanatory Notes).
This information is part of audited disclosure information (as defined in section 1.4 of this 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	123,153
10	*plus*	Gains / (losses) on asset disposals	(2,445)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)	666
12			
13		**Total regulatory income**	121,374
14		**Expenses**	
15	*less*	Operational expenditure	48,271
16			
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups	29,931
18			
19		**Operating surplus / (deficit)**	43,172
20			
21	*less*	Total depreciation	25,779
22			
23	*plus*	Total revaluations	42,563
24			
25		**Regulatory profit / (loss) before tax**	59,956
26			
27	*less*	Term credit spread differential allowance	–
28			
29	*less*	Regulatory tax allowance	4,066
30			
31		**Regulatory profit/(loss) including financial incentives and wash-ups**	55,890
32			

33	**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	**($000)**	
34	**Pass through costs**		
35	Rates	1,187	
36	Commerce Act levies	280	
37	Industry levies	295	
38	CPP specified pass through costs	–	
39	**Recoverable costs excluding financial incentives and wash-ups**		
40	Electricity lines service charge payable to Transpower	22,660	
41	Transpower new investment contract charges	520	
42	System operator services	–	
43	Distributed generation allowance	4,955	
44	Extended reserves allowance	–	
45	Other recoverable costs excluding financial incentives and wash-ups	34	
46	**Pass-through and recoverable costs excluding financial incentives and wash-ups**		29,931
47			

	Company Name	**Aurora Energy Limited**
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SCHEDULE 3: REPORT ON REGULATORY PROFIT

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sch ref				
48	**3(iii): Incremental Rolling Incentive Scheme**		**($000)**	
49			**CY-1**	**CY**
50				**31 Mar 23**
51	Allowed controllable opex			
52	Actual controllable opex			
53				
54	Incremental change in year			
55				
56			**Previous years' incremental change**	**Previous years' incremental change adjusted for inflation**
57	CY-5	[year]		
58	CY-4	[year]		
59	CY-3	[year]		
60	CY-2	[year]		
61	CY-1	[year]		
62	**Net incremental rolling incentive scheme**			–
63				
64	**Net recoverable costs allowed under incremental rolling incentive scheme**			–
65	**3(iv): Merger and Acquisition Expenditure**			
70				**($000)**
66	Merger and acquisition expenditure			–
67				
68	*Provide commentary on the benefits of merger and acquisition expenditure to the electricity distribution business, including required disclosures in accordance with section 2.7, in Schedule 14 (Mandatory Explanatory Notes)*			
69	**3(v): Other Disclosures**			
70				**($000)**
71	Self-insurance allowance			–

Company Name	**Aurora Energy Limited**
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SCHEDULE 4: REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)

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

sch ref

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

	RAB CY-4 ($000)	RAB CY-3 ($000)	RAB CY-2 ($000)	RAB CY-1 ($000)	RAB CY ($000)
Total opening RAB value	394,155	447,072	489,854	539,722	645,301
less **Total depreciation**	15,058	16,809	20,358	22,502	25,779
plus **Total revaluations**	5,824	11,277	7,402	37,128	42,563
plus **Assets commissioned**	63,004	49,227	61,073	93,006	76,873
less **Asset disposals**	853	912	830	2,087	2,871
plus **Lost and found assets adjustment**	–	–	2,581	–	–
plus **Adjustment resulting from asset allocation**	–	–	–	34	0
Total closing RAB value	447,072	489,854	539,722	645,301	736,088

4(ii): Unallocated Regulatory Asset Base

	Unallocated RAB * ($000)	 ($000)	RAB ($000)	 ($000)
Total opening RAB value		646,155		645,301
less				
Total depreciation		25,816		25,779
plus				
Total revaluations		42,620		42,563
plus				
Assets commissioned (other than below)	44,086		44,086	
Assets acquired from a regulated supplier	–		–	
Assets acquired from a related party	32,787		32,787	
Assets commissioned		76,873		76,873
less				
Asset disposals (other than below)	2,366		2,366	
Asset disposals to a regulated supplier	505		505	
Asset disposals to a related party	–		–	
Asset disposals		2,871		2,871
plus **Lost and found assets adjustment**		–		–
plus **Adjustment resulting from asset allocation**				0
Total closing RAB value		736,961		736,088

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

This schedule requires information on the calculation of the Regulatory Asset Base (RAB) value to the end of this disclosure year. This informs the ROI calculation in Schedule 2.
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sch ref						
51						
52		**4(iii): Calculation of Revaluation Rate and Revaluation of Assets**				
53						
54		CPI_4				1,218
55		CPI_4^{-4}				1,142
56		Revaluation rate (%)				6.65%
57						
58			**Unallocated RAB ***		**RAB**	
59			**($000)**	**($000)**	**($000)**	**($000)**
60		Total opening RAB value	646,155		645,301	
61	*less*	Opening value of fully depreciated, disposed and lost assets	5,737		5,737	
62						
63		Total opening RAB value subject to revaluation	640,418		639,564	
64		**Total revaluations**		42,620		42,563
65						
66		**4(iv): Roll Forward of Works Under Construction**				
67			**Unallocated works under construction**		**Allocated works under construction**	
68		**Works under construction—preceding disclosure year**		27,576		27,576
69	*plus*	Capital expenditure	86,616		86,616	
70	*less*	Assets commissioned	76,873		76,873	
71	*plus*	Adjustment resulting from asset allocation			–	
72		**Works under construction - current disclosure year**		37,319		37,319
73						
74		Highest rate of capitalised finance applied				4.35%
75						

Company Name	**Aurora Energy Limited**
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SCHEDULE 4: REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)

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

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

sch ref

76 4(v): Regulatory Depreciation

sch ref		Unallocated RAB * ($000)	Unallocated RAB * ($000)	RAB ($000)	RAB ($000)
79	Depreciation - standard	23,643		23,643	
80	Depreciation - no standard life assets	2,173		2,136	
81	Depreciation - modified life assets	–		–	
82	Depreciation - alternative depreciation in accordance with CPP	–		–	
83	**Total depreciation**		25,816		25,779
84					

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

($000 unless otherwise specified)

sch ref	Asset or assets with changes to depreciation*	Reason for non-standard depreciation (text entry)	Depreciation charge for the period (RAB)	Closing RAB value under 'non-standard' depreciation	Closing RAB value under 'standard' depreciation
87					
88					
89					
90					
91					
92					
93					
94					

95 ** include additional rows if needed*

96 4(vii): Disclosure by Asset Category

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

sch ref			Subtransmission lines	Subtransmission cables	Zone substations	Distribution and LV lines	Distribution and LV cables	Distribution substations and transformers	Distribution switchgear	Other network assets	Non-network assets	Total
99		**Total opening RAB value**	33,418	26,659	109,636	183,612	160,034	70,277	34,375	21,439	5,851	645,301
100	*less*	Total depreciation	1,154	781	4,164	5,660	5,275	2,626	1,713	2,269	2,136	25,779
101	*plus*	Total revaluations	2,238	1,774	7,195	12,134	10,590	4,677	2,246	1,398	311	42,563
102	*plus*	Assets commissioned	5,498	258	6,696	36,853	11,875	5,898	5,791	1,574	2,430	76,873
103	*less*	Asset disposals	–	3	–	1,109	914	–	643	–	202	2,871
104	*plus*	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
105	*plus*	Adjustment resulting from asset allocation	–	–	–	–	–	–	–	–	–	–
106	*plus*	Asset category transfers	212	–	–	(212)	–	–	–	–	–	–
107		**Total closing RAB value**	40,212	27,907	119,363	225,618	176,310	78,226	40,056	22,142	6,254	736,088
108												
109		**Asset Life**										
110		Weighted average remaining asset life	29.0	34.1	26.3	32.4	30.3	26.8	20.1	9.4	2.7	(years)
111		Weighted average expected total asset life	48.0	54.4	50.9	53.6	52.3	50.6	39.6	14.9	7.7	(years)

Company Name	**Aurora Energy Limited**
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SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

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

sch ref

5a(i): Regulatory Tax Allowance

sch ref				($000)	
8		**Regulatory profit / (loss) before tax**		59,956	
10	*plus*	Income not included in regulatory profit / (loss) before tax but taxable	–		*
11		Expenditure or loss in regulatory profit / (loss) before tax but not deductible	35		*
12		Amortisation of initial differences in asset values	4,929		
13		Amortisation of revaluations	4,371		
14				9,335	
16	*less*	Total revaluations	42,563		
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	1,131		*
20		Notional deductible interest	11,074		
21				54,768	
23		**Regulatory taxable income**		14,523	
25	*less*	Utilised tax losses	–		
26		Regulatory net taxable income		14,523	
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**		4,066	

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

sch ref				($000)
36		Opening unamortised initial differences in asset values	73,487	
37	*less*	Amortisation of initial differences in asset values	4,929	
38	*plus*	Adjustment for unamortised initial differences in assets acquired	–	
39	*less*	Adjustment for unamortised initial differences in assets disposed	440	
40		Closing unamortised initial differences in asset values		68,118
42		Opening weighted average remaining useful life of relevant assets (years)		15

Company Name	**Aurora Energy Limited**
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SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

This schedule requires information on the calculation of the regulatory tax allowance. This information is used to calculate regulatory profit/loss in Schedule 3 (regulatory profit). EDBs must provide explanatory commentary on the information disclosed in this schedule, in Schedule 14 (Mandatory Explanatory Notes).
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sch ref				
44	**5a(iv): Amortisation of Revaluations**			**($000)**
45				
46		Opening sum of RAB values without revaluations	558,758	
47				
48		Adjusted depreciation	21,408	
49		Total depreciation	25,779	
50		Amortisation of revaluations		4,371
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**	(30,287)	
61				
62	*plus*	Tax effect of adjusted depreciation	5,994	
63				
64	*less*	Tax effect of tax depreciation	10,147	
65				
66	*plus*	Tax effect of other temporary differences*	1,945	
67				
68	*less*	Tax effect of amortisation of initial differences in asset values	1,380	
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	(425)	
73				
74	*plus*	Deferred tax cost allocation adjustment	(0)	
75				
76		**Closing deferred tax**		(33,450)
77				
78	**5a(vii): Disclosure of Temporary Differences**			
79		*In Schedule 14, Box 6, provide descriptions and workings of items recorded in the asterisked category in Schedule 5a(vi) (Tax effect of other temporary differences).*		
80				
81	**5a(viii): Regulatory Tax Asset Base Roll-Forward**			
82				**($000)**
83		**Opening sum of regulatory tax asset values**	405,136	
84	*less*	Tax depreciation	36,240	
85	*plus*	Regulatory tax asset value of assets commissioned	86,229	
86	*less*	Regulatory tax asset value of asset disposals	1,352	
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**		453,773

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SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

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

sch ref			
7	**5b(i): Summary—Related Party Transactions**	**($000)**	**($000)**
8	**Total regulatory income**		–
9			
10	**Market value of asset disposals**		–
11			
12	Service interruptions and emergencies	2,842	
13	Vegetation management	5,454	
14	Routine and corrective maintenance and inspection	9,193	
15	Asset replacement and renewal (opex)	–	
16	**Network opex**		17,489
17	Business support	309	
18	System operations and network support	56	
19	**Operational expenditure**		17,854
20	Consumer connection	4,346	
21	System growth	2,530	
22	Asset replacement and renewal (capex)	23,406	
23	Asset relocations	1,722	
24	Quality of supply	–	
25	Legislative and regulatory	–	
26	Other reliability, safety and environment	1,361	
27	**Expenditure on non-network assets**		346
28	**Expenditure on assets**		33,711
29	Cost of financing		–
30	Value of capital contributions		3,506
31	Value of vested assets		–
32	**Capital Expenditure**		30,205
33	**Total expenditure**		48,059
34			
35	**Other related party transactions**		911

36 5b(iii): Total Opex and Capex Related Party Transactions

	Name of related party	Nature of opex or capex service provided	Total value of transactions ($000)
37			
38	Delta Utility Services Ltd	Service interruptions and emergencies	2,842
39	Delta Utility Services Ltd	Vegetation management	5,454
40	Delta Utility Services Ltd	Routine and corrective maintenance and inspection	9,193
41	Delta Utility Services Ltd	System operations and network support	56
42	Delta Utility Services Ltd	Business support	250
43	Dunedin City Council	Business support	58
44	Dunedin Venues Management Ltd	Business support	1
45	Delta Utility Services Ltd	Consumer connection	4,346
46	Delta Utility Services Ltd	System growth	2,530
47	Delta Utility Services Ltd	Asset replacement and renewal (capex)	23,406
48	Delta Utility Services Ltd	Asset relocations	1,722
49	Delta Utility Services Ltd	Other reliability, safety and environment	1,361
50	Delta Utility Services Ltd	Expenditure on non-network assets	346
51			
52			
53	**Total value of related party transactions**		51,565
54	** include additional rows if needed*		
55			

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**

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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

7

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

9

sch ref	Issuing party	Issue date	Pricing date	Original tenor (in years)	Coupon rate (%)	Book value at issue date (NZD)	Book value at date of financial statements (NZD)	Term Credit Spread Difference	Debt issue cost readjustment
10									
11									
12									
13									
14									
15									
16	** include additional rows if needed*						–	–	–

17

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

sch ref			
19			
20	**Gross term credit spread differential**		–
21			
22	Total book value of interest bearing debt		
23	Leverage	42%	
24	Average opening and closing RAB values		
25	**Attribution Rate (%)**		–
26			
27	**Term credit spread differential allowance**		–

	Company Name	**Aurora Energy Limited**
	For Year Ended	**31 March 2023**

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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref						
7	**5d(i): Operating Cost Allocations**					
8			**Value allocated ($000s)**			
9		**Arm's length deduction**	**Electricity distribution services**	**Non-electricity distribution services**	**Total**	**OVABAA allocation increase ($000s)**
10	**Service interruptions and emergencies**					
11	Directly attributable		2,882			
12	Not directly attributable		–	–	–	
13	**Total attributable to regulated service**		2,882			
14	**Vegetation management**					
15	Directly attributable		5,466			
16	Not directly attributable		–	–	–	
17	**Total attributable to regulated service**		5,466			
18	**Routine and corrective maintenance and inspection**					
19	Directly attributable		12,285			
20	Not directly attributable		–	–	–	
21	**Total attributable to regulated service**		12,285			
22	**Asset replacement and renewal**					
23	Directly attributable		–			
24	Not directly attributable		–	–	–	
25	**Total attributable to regulated service**		–			
26	**System operations and network support**					
27	Directly attributable		13,864			
28	Not directly attributable		–	–	–	
29	**Total attributable to regulated service**		13,864			
30	**Business support**					
31	Directly attributable		13,774			
32	Not directly attributable		–	–	–	
33	**Total attributable to regulated service**		13,774			
34						
35	**Operating costs directly attributable**		48,271			
36	**Operating costs not directly attributable**	–	–	–	–	–
37	**Operational expenditure**		48,271			
38						

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**

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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

5d(ii): Other Cost Allocations

	($000)
Pass through and recoverable costs	
Pass through costs	
Directly attributable	1,762
Not directly attributable	–
Total attributable to regulated service	1,762
Recoverable costs	
Directly attributable	28,169
Not directly attributable	–
Total attributable to regulated service	28,169

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

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

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

Change in cost allocation 3			($000) CY-1	Current Year (CY)
Cost category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	–	–
Rationale for change				

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**

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 this 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	40,211
Not directly attributable	–
Total attributable to regulated service	40,211
Subtransmission cables	
Directly attributable	27,906
Not directly attributable	–
Total attributable to regulated service	27,906
Zone substations	
Directly attributable	119,361
Not directly attributable	–
Total attributable to regulated service	119,361
Distribution and LV lines	
Directly attributable	225,619
Not directly attributable	–
Total attributable to regulated service	225,619
Distribution and LV cables	
Directly attributable	176,310
Not directly attributable	–
Total attributable to regulated service	176,310
Distribution substations and transformers	
Directly attributable	78,227
Not directly attributable	–
Total attributable to regulated service	78,227
Distribution switchgear	
Directly attributable	40,056
Not directly attributable	–
Total attributable to regulated service	40,056
Other network assets	
Directly attributable	19,426
Not directly attributable	2,716
Total attributable to regulated service	22,142
Non-network assets	
Directly attributable	6,255
Not directly attributable	–
Total attributable to regulated service	6,255
Regulated service asset value directly attributable	733,372
Regulated service asset value not directly attributable	2,716
Total closing RAB value	736,088

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

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

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

			($000) CY-1	Current Year (CY)
Change in asset value allocation 3				
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	–	–
Rationale for change				

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**

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 this 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		15,246
9		System growth		17,514
10		Asset replacement and renewal		54,604
11		Asset relocations		3,728
12		Reliability, safety and environment:		
13		Quality of supply	1,172	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	2,156	
16		**Total reliability, safety and environment**		3,328
17		**Expenditure on network assets**		94,420
18		Expenditure on non-network assets		2,735
19				
20		**Expenditure on assets**		97,155
21	*plus*	Cost of financing		400
22	*less*	Value of capital contributions		10,939
23	*plus*	Value of vested assets		–
24				
25		**Capital expenditure**		86,616
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		–
		Cybersecurity (Commission only)		–
30		**6a(iii): Consumer Connection**		
31		*Consumer types defined by EDB**	**($000)**	**($000)**
32		All consumers	15,246	
33				
34				
35				
36				
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		15,246
39				
40	*less*	Capital contributions funding consumer connection expenditure	7,780	
41		**Consumer connection less capital contributions**		7,466
42		**6a(iv): System Growth and Asset Replacement and Renewal**		
43			**System Growth**	**Asset Replacement and Renewal**
44			**($000)**	**($000)**
45		Subtransmission	5,729	100
46		Zone substations	6,153	12,656
47		Distribution and LV lines	3,345	33,561
48		Distribution and LV cables	2,118	2,713
49		Distribution substations and transformers	126	1,540
50		Distribution switchgear	43	3,979
51		Other network assets	–	55
52		**System growth and asset replacement and renewal expenditure**	17,514	54,604
53	*less*	Capital contributions funding system growth and asset replacement and renewal	–	–
54		**System growth and asset replacement and renewal less capital contributions**	17,514	54,604
55				
56		**6a(v): Asset Relocations**		
57		*Project or programme**	**($000)**	**($000)**
58		Mt Iron Wanaka roundabout	507	
59		Muir Skyline Queenstown overhead to underground conversion	504	
60		Corner Man/Thompson St roading works	505	
61		The Views, Queenstown overhead to underground conversion	457	
62		Gibbston Valley overhead to underground conversion	358	
63		** include additional rows if needed*		
64		All other projects or programmes - asset relocations	1,397	
65		**Asset relocations expenditure**		3,728
66	*less*	Capital contributions funding asset relocations	3,159	
67		**Asset relocations less capital contributions**		569

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**

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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref			($000)	($000)
68				
69	**6a(vi): Quality of Supply**			
70		*Project or programme**	($000)	($000)
71		Lowburn voltage regulator replacement	302	
72		Brecon St Queenstown feeder upgrade	246	
73		Two new 11kV reclosers Matakanui	176	
74				
75				
76		** include additional rows if needed*		
77		All other projects programmes - quality of supply	448	
78	**Quality of supply expenditure**			1,172
79	*less*	Capital contributions funding quality of supply	–	
80	**Quality of supply less capital contributions**			1,172
81	**6a(vii): Legislative and Regulatory**			
82		*Project or programme**	($000)	($000)
83				
84				
85				
86				
87				
88		** include additional rows if needed*		
89		All other projects or programmes - legislative and regulatory		
90	**Legislative and regulatory expenditure**			–
91	*less*	Capital contributions funding legislative and regulatory		
92	**Legislative and regulatory less capital contributions**			–
93	**6a(viii): Other Reliability, Safety and Environment**			
94		*Project or programme**	($000)	($000)
95		Camp Hill 2MVA generator	1,075	
96		Omakau 2MVA generator	1,080	
97				
98				
99				
100		** include additional rows if needed*		
101		All other projects or programmes - other reliability, safety and environment	1	
102	**Other reliability, safety and environment expenditure**			2,156
103	*less*	Capital contributions funding other reliability, safety and environment	–	
104	**Other reliability, safety and environment less capital contributions**			2,156
105				
106	**6a(ix): Non-Network Assets**			
107	**Routine expenditure**			
108		*Project or programme**	($000)	($000)
109		Right-of-use assets	193	
110				
111				
112				
113				
114		** include additional rows if needed*		
115		All other projects or programmes - routine expenditure	14	
116	**Routine expenditure**			207
117	**Atypical expenditure**			
118		*Project or programme**	($000)	($000)
119		Operational technology	1,242	
120		Enterprise technology and infrastructure	501	
121		New offices	297	
122		Development of outage management system	278	
123				
124		** include additional rows if needed*		
125		All other projects or programmes - atypical expenditure	210	
126	**Atypical expenditure**			2,528
127				
128	**Expenditure on non-network assets**			2,735

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**

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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref			
7	**6b(i): Operational Expenditure**	**($000)**	**($000)**
8	Service interruptions and emergencies	2,882	
9	Vegetation management	5,466	
10	Routine and corrective maintenance and inspection	12,285	
11	Asset replacement and renewal		
12	**Network opex**		20,633
13	System operations and network support	13,864	
14	Business support	13,774	
15	**Non-network opex**		27,638
16			
17	**Operational expenditure**		48,271
18	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
19	*EDBs’ must disclose both a public version of this Schedule (excluding cybersecurity cost data) and a confidential version of this Schedule (including cybersecurity costs)*		
20	Energy efficiency and demand side management, reduction of energy losses		–
21	Direct billing*		–
22	Research and development		–
23	Insurance		501
24	Cybersecurity (Commission only)		–
25	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**

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 this 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	121,784	123,153	1%
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	13,564	15,246	12%
11	System growth	12,699	17,514	38%
12	Asset replacement and renewal	56,231	54,604	(3%)
13	Asset relocations	2,683	3,728	39%
14	Reliability, safety and environment:			
15	Quality of supply	1,406	1,172	(17%)
16	Legislative and regulatory	–	–	–
17	Other reliability, safety and environment	–	2,156	–
18	**Total reliability, safety and environment**	1,406	3,328	137%
19	**Expenditure on network assets**	86,583	94,420	9%
20	Expenditure on non-network assets	4,042	2,735	(32%)
21	Expenditure on assets	90,625	97,155	7%
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	4,813	2,882	(40%)
24	Vegetation management	5,256	5,466	4%
25	Routine and corrective maintenance and inspection	10,117	12,285	21%
26	Asset replacement and renewal	–	–	–
27	**Network opex**	20,186	20,633	2%
28	System operations and network support	14,259	13,864	(3%)
29	Business support	13,855	13,774	(1%)
30	**Non-network opex**	28,114	27,638	(2%)
31	**Operational expenditure**	48,300	48,271	(0%)
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	–	501	–
42				

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

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**
Network / Sub-Network Name	**Total Network**

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

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

9

10

11 **Billed quantities by price component**

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

sch ref	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)	Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Period Demand (Distribution)	Transformer Lease, Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Transmission)
12					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 (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Transmission)
13					Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	LS	Lamp	kWh	kVA	kVA x km	kW	kVA	LS	kWh	kVA	kW
14																
15	Residential	Residential	Standard	78,946	629,624	28,833,507	–	629,624,383	–	–	–	–	–	629,053,719	–	–
16	Load Group 0	General	Standard	319	213	116,700	–	–	101	–	–	–	116,700	–	–	–
17	Load Group 0A	General	Standard	794	1,932	290,009	–	–	344	–	–	–	62,787	–	–	–
18	Load Group 1A	General	Standard	928	3,187	338,978	–	–	2,709,176	–	322,007	–	–	–	2,707,224	321,763
19	Load Group 1	General	Standard	5,644	43,402	2,061,996	–	–	30,899,475	–	4,824,645	–	–	–	30,899,475	4,824,645
20	Load Group 2	General	Standard	7,103	275,775	2,594,762	–	–	128,760,796	–	16,981,494	(511)	–	–	128,733,712	16,980,154
21	Load Group 2	General	Non-standard	0	–	33	–	–	–	–	–	–	–	–	–	–
22	Load Group 3	General	Standard	234	57,173	85,364	–	–	16,283,386	262,895,109	3,290,407	(140)	–	–	16,283,386	3,290,407
23	Load Group 3	General	Non-standard	0	–	24	–	–	–	–	–	–	–	–	–	–
	Load Group 3A	General	Standard	180	86,882	65,627	–	–	20,130,092	283,346,873	5,001,517	(430)	–	–	20,130,092	5,001,517
	Load Group 3A	General	Non-standard	0	–	24	–	–	–	–	–	–	–	–	–	–
	Load Group 4	General	Standard	147	185,259	53,729	–	–	38,402,350	609,739,658	9,481,531	93,238	–	–	38,402,350	9,481,531
	Load Group 4	General	Non-standard	1	4,141	365	–	–	–	–	–	–	365	–	–	–
	Load Group 5	General	Standard	8	56,446	2,921	–	–	8,687,000	108,909,065	2,330,480	8,167	–	–	8,687,000	2,330,480
	Load Group 5	General	Non-standard	1	5,402	365	–	–	–	–	–	–	365	–	–	–
	Street Lighting	General	Standard	6	5,896	730	2,711,766	1,609,327	–	–	–	–	730	1,603,716	–	–
	DUML, excl Street Lighting	General	Standard	–	4	–	–	4,228	–	–	–	–	–	4,228	–	–
24	Distributed Generation (Large)	General	Non-standard	12	–	–	–	–	–	–	–	–	–	–	–	–
25	*Add extra rows for additional consumer groups or price category codes as necessary*															
26			**Standard consumer totals**	94,309	1,345,795	34,444,325	2,711,766	631,237,938	245,872,720	1,264,890,705	42,232,081	100,323	180,217	630,661,663	245,843,239	42,230,497
27			**Non-standard consumer totals**	14	9,543	811	–	–	–	–	–	–	730	–	–	–
28			**Total for all consumers**	94,323	1,355,338	34,445,136	2,711,766	631,237,938	245,872,720	1,264,890,705	42,232,081	100,323	180,947	630,661,663	245,843,239	42,230,497

29

30

Company Name	Aurora Energy Limited
For Year Ended	31 March 2023
Network / Sub-Network Name	Total 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.

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

Row	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)
37	Residential	Residential	Standard	$72,823		$49,720	$23,104
38	Load Group 0	General	Standard	$58		$34	$24
39	Load Group 0A	General	Standard	$315		$150	$165
40	Load Group 1A	General	Standard	$669		$312	$357
41	Load Group 1	General	Standard	$3,887		$2,391	$1,495
42	Load Group 2	General	Standard	$16,182		$10,914	$5,269
43	Load Group 2	General	Non-standard	$5,812		$4,449	$1,363
44	Load Group 3	General	Standard	$2,856		$2,043	$813
45	Load Group 3	General	Non-standard	$1,474		$1,039	$434
	Load Group 3A	General	Standard	$4,295		$2,816	$1,479
	Load Group 3A	General	Non-standard	$1,336		$1,202	$134
	Load Group 4	General	Standard	$6,868		$4,055	$2,813
	Load Group 4	General	Non-standard	$3,293		$2,635	$658
	Load Group 5	General	Standard	$1,579		$792	$787
	Load Group 5	General	Non-standard	$361		$220	$141
	Street Lighting	General	Standard	$561		$422	$138
	DUML, excl Street Lighting	General	Standard	$152		$117	$35
46	Distributed Generation (Large)	General	Non-standard	$631		$631	–
47	*Add extra rows for additional consumer groups or price category codes as necessary*						
48			**Standard consumer totals**	$110,245	–	$73,766	$36,479
49			**Non-standard consumer totals**	$12,907	–	$10,178	$2,730
50			**Total for all consumers**	$123,153	–	$83,944	$39,209

Line charge revenues ($000) by price component

Row	Consumer group name or price category code	Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Period Demand (Distribution)	Transformer Lease, Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Transmission)
35	**Rate (eg, $ per day, $ per kWh, etc.)**	$ / annum	$ / Lamp	$ / kWh	$ / kVA	$ / kVA x km	$ / kW	$ / kVA	$ / annum	$ / kWh	$ / kVA	$ / kW
37	Residential	$8,585	–	$41,135	–	–	–	–	–	$23,104	–	–
38	Load Group 0	$34	–	–	–	–	–	–	$24	–	–	–
39	Load Group 0A	$150	–	–	–	–	–	–	$165	–	–	–
40	Load Group 1A	$154	–	–	$56	–	$102	–	$278	–	$37	$42
41	Load Group 1	$64	–	–	$438	–	$1,889	–	–	–	$697	$798
42	Load Group 2	$162	–	–	$2,728	–	$8,025	($2)	–	–	$2,452	$2,816
43	Load Group 2	$61	–	–	$2,071	–	$2,322	($5)	–	–	$720	$643
44	Load Group 3	$82	–	–	$659	$82	$1,221	($1)	–	–	$483	$330
45	Load Group 3	$54	–	–	$204	$207	$576	($2)	–	–	$241	$193
	Load Group 3A	$73	–	–	$620	$114	$2,011	($2)	–	–	$829	$650
	Load Group 3A	$34	–	–	$40	$198	$934	($3)	–	–	$68	$66
	Load Group 4	$164	–	–	$300	$199	$2,802	$590	–	–	$1,358	$1,455
	Load Group 4	$146	–	–	$615	$471	$1,205	$198	$54	–	$303	$301
	Load Group 5	$11	–	–	$35	$54	$599	$94	–	–	$382	$404
	Load Group 5	$94	–	–	$33	$66	$27	–	$114	–	$14	$13
	Street Lighting	$375	$39	$9	–	–	–	–	$109	$30	–	–
	DUML, excl Street Lighting	$29	$50	$38	–	–	–	–	–	$35	–	–
46	Distributed Generation (Large)	$631	–	–	–	–	–	–	–	–	–	–
48	**Standard consumer totals**	$9,882	$88	$41,182	$4,837	$450	$16,649	$679	$575	$23,168	$6,239	$6,496
49	**Non-standard consumer totals**	$1,020	–	–	$2,964	$942	$5,064	$188	$168	–	$1,345	$1,217
50	**Total for all consumers**	$10,901	$88	$41,182	$7,801	$1,391	$21,713	$867	$743	$23,168	$7,584	$7,713

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

Check OK

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

53	**Number of directly billed ICPs at year end**	10

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**
Network / Sub-Network Name	**Dunedin Sub-network**

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

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

sch ref	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)
15	Residential	Residential	Standard	49,551	397,803
16	Load Group 0	General	Standard	101	61
17	Load Group 0A	General	Standard	172	463
18	Load Group 1A	General	Standard	410	1,411
19	Load Group 1	General	Standard	2,806	21,206
20	Load Group 2	General	Standard	3,158	130,567
21	Load Group 2	General	Non-standard	–	–
22	Load Group 3	General	Standard	107	30,411
23	Load Group 3	General	Non-standard	–	–
	Load Group 3A	General	Standard	92	50,709
	Load Group 3A	General	Non-standard	–	–
	Load Group 4	General	Standard	74	100,821
	Load Group 4	General	Non-standard	–	–
	Load Group 5	General	Standard	6	44,843
	Load Group 5	General	Non-standard	–	–
	Street Lighting	General	Standard	2	4,287
	DUML, excl Street Lighting	General	Standard	–	4
24	Distributed Generation (Large)	General	Non-standard	1	–
25	*Add extra rows for additional consumer groups or price category codes as necessary*				
26			**Standard consumer totals**	56,480	782,587
27			**Non-standard consumer totals**	1	–
28			**Total for all consumers**	56,481	782,587

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 (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Transmission)
Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	LS	Lamp	kWh	kVA	kVA x km	kW	kVA	LS	kWh	kVA	kW
Residential (Standard)	18,085,939	–	397,803,086	–	–	–	–	–	397,803,086	–	–
Load Group 0 (Standard)	36,963	–	–	101	–	–	–	36,963	–	–	–
Load Group 0A (Standard)	62,787	–	–	344	–	–	–	62,787	–	–	–
Load Group 1A (Standard)	149,708	–	–	1,197,664	–	140,664	–	–	–	1,197,664	140,664
Load Group 1 (Standard)	1,024,238	–	–	15,359,820	–	2,322,415	–	–	–	15,359,820	2,322,415
Load Group 2 (Standard)	1,152,671	–	–	58,947,890	–	8,211,930	–	–	–	58,947,890	8,211,930
Load Group 2 (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
Load Group 3 (Standard)	39,131	–	–	7,636,368	43,113,925	1,870,608	–	–	–	7,636,368	1,870,608
Load Group 3 (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
Load Group 3A (Standard)	33,556	–	–	10,195,126	55,104,589	3,179,985	(150)	–	–	10,195,126	3,179,985
Load Group 3A (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
Load Group 4 (Standard)	27,146	–	–	19,279,750	108,299,201	5,310,327	48,175	–	–	19,279,750	5,310,327
Load Group 4 (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
Load Group 5 (Standard)	2,190	–	–	6,862,000	47,680,315	2,097,868	8,167	–	–	6,862,000	2,097,868
Load Group 5 (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
Street Lighting (Standard)	730	–	–	–	–	–	–	730	–	–	–
DUML, excl Street Lighting (Standard)	–	–	4,228	–	–	–	–	–	4,228	–	–
Distributed Generation (Large) (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
Standard consumer totals	20,615,059	–	397,807,314	119,479,063	254,198,030	23,133,797	56,192	100,480	397,807,314	119,478,618	23,133,797
Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–	–
Total for all consumers	20,615,059	–	397,807,314	119,479,063	254,198,030	23,133,797	56,192	100,480	397,807,314	119,478,618	23,133,797

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**
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.

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)	Total distribution line charge revenue	Total transmission line charge revenue (if available)
Residential	Residential	Standard	$39,480		$26,067	$13,413
Load Group 0	General	Standard	$22		$17	$5
Load Group 0A	General	Standard	$85		$60	$24
Load Group 1A	General	Standard	$180		$121	$59
Load Group 1	General	Standard	$2,744		$1,694	$1,050
Load Group 2	General	Standard	$10,050		$6,516	$3,534
Load Group 2	General	Non-standard	–		–	–
Load Group 3	General	Standard	$2,069		$1,386	$684
Load Group 3	General	Non-standard	–		–	–
Load Group 3A	General	Standard	$3,233		$1,918	$1,315
Load Group 3A	General	Non-standard	–		–	–
Load Group 4	General	Standard	$4,834		$2,894	$1,939
Load Group 4	General	Non-standard	–		–	–
Load Group 5	General	Standard	$1,461		$731	$731
Load Group 5	General	Non-standard	–		–	–
Street Lighting	General	Standard	$483		$375	$109
DUML, excl Street Lighting	General	Standard	$0		$0	$0
Distributed Generation (Large)	General	Non-standard	$139		$139	–
Add extra rows for additional consumer groups or price category codes as necessary						
		Standard consumer totals	$64,641	–	$41,780	$22,862
		Non-standard consumer totals	$139	–	$139	–
		Total for all consumers	$64,781	–	$41,919	$22,862

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 (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Transmission)
Rate (eg, $ per day, $ per kWh, etc.)	$ / annum	$ / Lamp	$ / kWh	$ / kVA	$ / kVA x km	$ / kW	$ / kVA	$ / annum	$ / kWh	$ / kVA	$ / kW
Residential	$5,382	–	$20,686	–	–	–	–	–	$13,413	–	–
Load Group 0	$17	–	–	–	–	–	–	$5	–	–	–
Load Group 0A	$60	–	–	–	–	–	–	$24	–	–	–
Load Group 1A	$6	–	–	$40	–	$74	–	–	–	$30	$29
Load Group 1	$44	–	–	$307	–	$1,343	–	–	–	$535	$516
Load Group 2	$97	–	–	$1,509	–	$4,910	–	–	–	$1,816	$1,718
Load Group 2	–	–	–	–	–	–	–	–	–	–	–
Load Group 3	$63	–	–	$379	$47	$898	($1)	–	–	$354	$329
Load Group 3	–	–	–	–	–	–	–	–	–	–	–
Load Group 3A	$54	–	–	$228	$61	$1,577	($2)	–	–	$667	$648
Load Group 3A	–	–	–	–	–	–	–	–	–	–	–
Load Group 4	$120	–	–	$79	$119	$2,168	$408	–	–	$989	$950
Load Group 4	–	–	–	–	–	–	–	–	–	–	–
Load Group 5	$10	–	–	$28	$52	$567	$73	–	–	$377	$353
Load Group 5	–	–	–	–	–	–	–	–	–	–	–
Street Lighting	$375	–	–	–	–	–	–	$109	–	–	–
DUML, excl Street Lighting	$0	–	$0	–	–	–	–	–	$0	–	–
Distributed Generation (Large)	$139	–	–	–	–	–	–	–	–	–	–
Standard consumer totals	$6,229	–	$20,686	$2,570	$280	$11,537	$478	$138	$13,413	$4,767	$4,543
Non-standard consumer totals	$139	–	–	–	–	–	–	–	–	–	–
Total for all consumers	$6,368	–	$20,686	$2,570	$280	$11,537	$478	$138	$13,413	$4,767	$4,543

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

Check OK

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	1

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**
Network / Sub-Network Name	**Central Otago and Wanaka Sub-network**

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

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

9

10

11

sch ref	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)
15	Residential	Residential	Standard	18,065	127,890
16	Load Group 0	General	Standard	109	79
17	Load Group 0A	General	Standard	374	797
18	Load Group 1A	General	Standard	331	1,174
19	Load Group 1	General	Standard	1,781	13,152
20	Load Group 2	General	Standard	2,097	79,605
21	Load Group 2	General	Non-standard	0	–
22	Load Group 3	General	Standard	89	16,595
23	Load Group 3	General	Non-standard	0	–
	Load Group 3A	General	Standard	51	22,975
	Load Group 3A	General	Non-standard	0	–
	Load Group 4	General	Standard	41	40,987
	Load Group 4	General	Non-standard	–	–
	Load Group 5	General	Standard	1	8,348
	Load Group 5	General	Non-standard	–	–
	Street Lighting	General	Standard	0	914
	DUML, excl Street Lighting	General	Standard	–	–
24	Distributed Generation (Large)	General	Non-standard	9	–
25	*Add extra rows for additional consumer groups or price category codes as necessary*				
26			**Standard consumer totals**	22,941	312,515
27			**Non-standard consumer totals**	9	–
28			**Total for all consumers**	22,950	312,515

29

30

Billed quantities by price component

sch ref	Consumer group name or price category code	Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Period Demand (Distribution)	Transformer Lease, Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Transmission)
13	**Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)**	LS	Lamp	kWh	kVA	kVA x km	kW	kVA	LS	kWh	kVA	kW
15	Residential	6,611,792	–	127,889,634	–	–	–	–	–	127,889,634	–	–
16	Load Group 0	39,949	–	–	–	–	–	–	39,949	–	–	–
17	Load Group 0A	136,961	–	–	–	–	–	–	–	–	–	–
18	Load Group 1A	121,165	–	–	966,672	–	114,312	–	–	–	966,672	114,312
19	Load Group 1	651,765	–	–	9,749,760	–	1,404,294	–	–	–	9,749,760	1,404,294
20	Load Group 2	767,611	–	–	38,905,766	–	4,118,351	(385)	–	–	38,905,766	4,118,351
21	Load Group 2	33	–	–	–	–	–	–	–	–	–	–
22	Load Group 3	32,710	–	–	6,062,453	187,983,803	734,423	(140)	–	–	6,062,453	734,423
23	Load Group 3	24	–	–	–	–	–	–	–	–	–	–
	Load Group 3A	18,773	–	–	5,987,318	179,621,489	935,139	(280)	–	–	5,987,318	935,139
	Load Group 3A	24	–	–	–	–	–	–	–	–	–	–
	Load Group 4	15,148	–	–	11,246,100	428,217,540	1,874,776	23,563	–	–	11,246,100	1,874,776
	Load Group 4	–	–	–	–	–	–	–	–	–	–	–
	Load Group 5	366	–	–	912,500	60,133,750	36,972	–	–	–	912,500	36,972
	Load Group 5	–	–	–	–	–	–	–	–	–	–	–
	Street Lighting	–	1,634,829	913,605	–	–	–	–	–	913,605	–	–
	DUML, excl Street Lighting	–	–	–	–	–	–	–	–	–	–	–
24	Distributed Generation (Large)	–	–	–	–	–	–	–	–	–	–	–
26	**Standard consumer totals**	8,396,242	1,634,829	128,803,239	73,830,569	855,956,582	9,218,267	22,758	39,949	128,803,239	73,830,569	9,218,267
27	**Non-standard consumer totals**	81	–	–	–	–	–	–	–	–	–	–
28	**Total for all consumers**	8,396,323	1,634,829	128,803,239	73,830,569	855,956,582	9,218,267	22,758	39,949	128,803,239	73,830,569	9,218,267

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

Company Name: **Aurora Energy Limited**
For Year Ended: **31 March 2023**
Network / Sub-Network Name: **Central Otago and Wanaka 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.

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

Row	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)
37	Residential	Residential	Standard	$20,404		$15,306	$5,098
38	Load Group 0	General	Standard	–		–	–
39	Load Group 0A	General	Standard	$62		$22	$40
40	Load Group 1A	General	Standard	$422		$145	$278
41	Load Group 1	General	Standard	$127		$117	$10
42	Load Group 2	General	Standard	$1,299		$1,289	$10
43	Load Group 2	General	Non-standard	$5,812		$4,449	$1,363
44	Load Group 3	General	Standard	–		–	–
45	Load Group 3	General	Non-standard	$1,474		$1,039	$434
	Load Group 3A	General	Standard	–		–	–
	Load Group 3A	General	Non-standard	$1,336		$1,202	$134
	Load Group 4	General	Standard	–		–	–
	Load Group 4	General	Non-standard	$3,160		$2,556	$604
	Load Group 5	General	Standard	–		–	–
	Load Group 5	General	Non-standard	$155		$128	$27
	Street Lighting	General	Standard	–		–	–
	DUML, excl Street Lighting	General	Standard	$123		$88	$35
46	Distributed Generation (Large)	General	Non-standard	$491		$491	–
47	*Add extra rows for additional consumer groups or price category codes as necessary*						
48			Standard consumer totals	$22,437	–	$16,967	$5,470
49			Non-standard consumer totals	$12,429	–	$9,867	$2,562
50			Total for all consumers	$34,866	–	$26,834	$8,032

33 **Line charge revenues ($000) by price component**

Row	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 (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Transmission)
35	Rate (eg, $ per day, $ per kWh, etc.)	$ / annum	$ / Lamp	$ / kWh	$ / kVA	$ / kVA x km	$ / kW	$ / kVA	$ / annum	$ / kWh	$ / kVA	$ / kW
37	Residential	$1,971	–	$13,335	–	–	–	–	–	$5,098	–	–
38	Load Group 0	–	–	–	–	–	–	–	–	–	–	–
39	Load Group 0A	$22	–	–	–	–	–	–	$40	–	–	–
40	Load Group 1A	$145	–	–	–	–	–	–	$278	–	–	–
41	Load Group 1	$5	–	–	$41	–	$71	–	–	–	$6	$4
42	Load Group 2	$26	–	–	$310	–	$954	($0)	–	–	$7	$3
43	Load Group 2	$61	–	–	$2,071	–	$2,322	($5)	–	–	$720	$643
44	Load Group 3	–	–	–	–	–	–	–	–	–	–	–
45	Load Group 3	$54	–	–	$204	$207	$576	($2)	–	–	$241	$193
	Load Group 3A	–	–	–	–	–	–	–	–	–	–	–
	Load Group 3A	$34	–	–	$40	$198	$934	($3)	–	–	$68	$66
	Load Group 4	–	–	–	–	–	–	–	–	–	–	–
	Load Group 4	$67	–	–	$615	$471	$1,205	$198	–	–	$303	$301
	Load Group 5	–	–	–	–	–	–	–	–	–	–	–
	Load Group 5	$2	–	–	$33	$66	$27	–	–	–	$14	$13
	Street Lighting	–	–	–	–	–	–	–	–	–	–	–
	DUML, excl Street Lighting	–	$50	$38	–	–	–	–	–	$35	–	–
46	Distributed Generation (Large)	$491	–	–	–	–	–	–	–	–	–	–
48	Standard consumer totals	$2,168	$50	$13,373	$351	–	$1,025	($0)	$317	$5,133	$12	$7
49	Non-standard consumer totals	$709	–	–	$2,964	$942	$5,064	$188	–	–	$1,345	$1,217
50	Total for all consumers	$2,878	$50	$13,373	$3,315	$942	$6,089	$188	$317	$5,133	$1,357	$1,224

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

Check: **OK**

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

53 **Number of directly billed ICPs at year end**: 4

Company Name	Aurora Energy Limited
For Year Ended	31 March 2023
Network / Sub-Network Name	Queenstown Sub-network

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

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

sch ref	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)
15	Residential	Residential	Standard	11,240	103,361
16	Load Group 0	General	Standard	109	73
17	Load Group 0A	General	Standard	246	671
18	Load Group 1A	General	Standard	186	600
19	Load Group 1	General	Standard	1,058	9,043
20	Load Group 2	General	Standard	1,845	65,572
21	Load Group 2	General	Non-standard	–	–
22	Load Group 3	General	Standard	37	10,168
23	Load Group 3	General	Non-standard	–	–
	Load Group 3A	General	Standard	36	13,199
	Load Group 3A	General	Non-standard	–	–
	Load Group 4	General	Standard	31	43,451
	Load Group 4	General	Non-standard	1	4,141
	Load Group 5	General	Standard	1	3,255
	Load Group 5	General	Non-standard	1	5,402
	Street Lighting	General	Standard	3	690
	DUML, excl Street Lighting	General	Standard	–	–
24	Distributed Generation (Large)	General	Non-standard	2	–
25	*Add extra rows for additional consumer groups or price category codes as necessary*				
26			Standard consumer totals	14,793	250,081
27			Non-standard consumer totals	4	9,543
28			Total for all consumers	14,797	259,624

Billed quantities by price component

Consumer group name or price category code	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 (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Transmission)
	Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	LS	Lamp	kWh	kVA	kVA x km	kW	kVA	LS	kWh	kVA	kW
Residential		4,102,751	–	103,360,999	–	–	–	–	–	103,360,999	–	–
Load Group 0		39,788	–	–	–	–	–	–	39,788	–	–	–
Load Group 0A		89,773	–	–	–	–	–	–	–	–	–	–
Load Group 1A		67,861	–	–	542,888	–	66,787	–	–	–	542,888	66,787
Load Group 1		385,993	–	–	5,789,895	–	1,097,936	–	–	–	5,789,895	1,097,936
Load Group 2		673,504	–	–	30,880,056	–	4,649,873	(126)	–	–	30,880,056	4,649,873
Load Group 2		–	–	–	–	–	–	–	–	–	–	–
Load Group 3		13,523	–	–	2,584,565	31,797,381	685,376	–	–	–	2,584,565	685,376
Load Group 3		–	–	–	–	–	–	–	–	–	–	–
Load Group 3A		13,298	–	–	3,947,648	48,620,795	886,393	–	–	–	3,947,648	886,393
Load Group 3A		–	–	–	–	–	–	–	–	–	–	–
Load Group 4		11,435	–	–	7,876,500	73,222,917	2,296,428	21,500	–	–	7,876,500	2,296,428
Load Group 4		365	–	–	–	–	–	–	365	–	–	–
Load Group 5		365	–	–	912,500	1,095,000	195,640	–	–	–	912,500	195,640
Load Group 5		365	–	–	–	–	–	–	365	–	–	–
Street Lighting		–	1,057,173	690,111	–	–	–	–	–	690,111	–	–
DUML, excl Street Lighting		–	–	–	–	–	–	–	–	–	–	–
Distributed Generation (Large)		–	–	–	–	–	–	–	–	–	–	–
Standard consumer totals		5,398,291	1,057,173	104,051,110	52,534,052	154,736,093	9,878,433	21,374	39,788	104,051,110	52,534,052	9,878,433
Non-standard consumer totals		730	–	–	–	–	–	–	730	–	–	–
Total for all consumers		5,399,021	1,057,173	104,051,110	52,534,052	154,736,093	9,878,433	21,374	40,518	104,051,110	52,534,052	9,878,433

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**
Network / Sub-Network Name	**Queenstown 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.

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

Row	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)
37	Residential	Residential	Standard	$12,854		$8,262	$4,592
38	Load Group 0	General	Standard	$35		$16	$19
39	Load Group 0A	General	Standard	$168		$67	$101
40	Load Group 1A	General	Standard	$67		$46	$21
41	Load Group 1	General	Standard	$1,016		$581	$435
42	Load Group 2	General	Standard	$4,831		$3,105	$1,725
43	Load Group 2	General	Non-standard	–		–	–
44	Load Group 3	General	Standard	$787		$657	$130
45	Load Group 3	General	Non-standard	–		–	–
	Load Group 3A	General	Standard	$1,063		$898	$164
	Load Group 3A	General	Non-standard	–		–	–
	Load Group 4	General	Standard	$2,035		$1,161	$874
	Load Group 4	General	Non-standard	$133		$79	$54
	Load Group 5	General	Standard	$118		$62	$56
	Load Group 5	General	Non-standard	$206		$92	$114
	Street Lighting	General	Standard	$76		$46	$30
	DUML, excl Street Lighting	General	Standard	$29		$29	–
46	Distributed Generation (Large)	General	Non-standard	–		–	–
47	*Add extra rows for additional consumer groups or price category codes as necessary*						
48			**Standard consumer totals**	$23,077	–	$14,930	$8,147
49			**Non-standard consumer totals**	$339	–	$171	$168
50			**Total for all consumers**	$23,416	–	$15,101	$8,315

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 (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Transmission)
Rate (eg, $ per day, $ per kWh, etc.)	$ / annum	$ / Lamp	$ / kWh	$ / kVA	$ / kVA x km	$ / kW	$ / kVA	$ / annum	$ / kWh	$ / kVA	$ / kW
Residential	$1,223	–	$7,039	–	–	–	–	–	$4,592	–	–
Load Group 0	$16	–	–	–	–	–	–	$19	–	–	–
Load Group 0A	$67	–	–	–	–	–	–	$101	–	–	–
Load Group 1A	$3	–	–	$16	–	$27	–	–	–	$8	$13
Load Group 1	$15	–	–	$90	–	$475	–	–	–	$157	$278
Load Group 2	$39	–	–	$907	–	$2,160	($2)	–	–	$630	$1,096
Load Group 2	–	–	–	–	–	–	–	–	–	–	–
Load Group 3	$19	–	–	$280	$35	$323	–	–	–	$129	$1
Load Group 3	–	–	–	–	–	–	–	–	–	–	–
Load Group 3A	$19	–	–	$392	$54	$434	–	–	–	$162	$2
Load Group 3A	–	–	–	–	–	–	–	–	–	–	–
Load Group 4	$44	–	–	$221	$80	$635	$181	–	–	$369	$505
Load Group 4	$79	–	–	–	–	–	–	$54	–	–	–
Load Group 5	$1	–	–	$7	$1	$31	$21	–	–	$5	$51
Load Group 5	$92	–	–	–	–	–	–	$114	–	–	–
Street Lighting	–	$38	$9	–	–	–	–	–	$30	–	–
DUML, excl Street Lighting	$29	–	–	–	–	–	–	–	–	–	–
Distributed Generation (Large)	–	–	–	–	–	–	–	–	–	–	–
Standard consumer totals	$1,474	$38	$7,048	$1,914	$170	$4,085	$201	$120	$4,622	$1,460	$1,946
Non-standard consumer totals	$171	–	–	–	–	–	–	$168	–	–	–
Total for all consumers	$1,645	$38	$7,048	$1,914	$170	$4,085	$201	$288	$4,622	$1,460	$1,946

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

Check OK

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

53 **Number of directly billed ICPs at year end** 5

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**
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

	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
8								
9	All	Overhead Line	Concrete poles / steel structure	No.	29,480	30,590	1,110	4
10	All	Overhead Line	Wood poles	No.	24,194	23,065	(1,129)	4
11	All	Overhead Line	Other pole types	No.			–	3
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	523	522	(1)	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km			–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	35	36	1	3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	25	25	(0)	3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	16	16	(0)	3
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	11	11	(0)	3
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km			–	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km			–	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km			–	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km			–	N/A
22	HV	Subtransmission Cable	Subtransmission submarine cable	km			–	N/A
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	35	36	1	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.	14	14	–	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.			–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	145	153	8	4
29	HV	Zone substation switchgear	33kV RMU	No.	1	1	–	4
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	9	9	–	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	52	57	5	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	332	334	2	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	22	24	2	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	67	68	1	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2,279	2,276	(2)	4
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km			–	N/A
37	HV	Distribution Line	SWER conductor	km	9	9	(0)	4
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	748	778	29	3
39	HV	Distribution Cable	Distribution UG PILC	km	418	413	(5)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	5	5	–	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	56	58	2	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	6	6	–	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	7,164	7,250	86	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	509	480	(29)	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	888	933	45	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	3,984	3,991	7	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	3,259	3,312	53	4
48	HV	Distribution Transformer	Voltage regulators	No.	28	32	4	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	350	345	(5)	4
50	LV	LV Line	LV OH Conductor	km	1,032	1,028	(4)	4
51	LV	LV Cable	LV UG Cable	km	1,112	1,136	24	4
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	1,069	1,071	3	4
53	LV	Connections	OH/UG consumer service connections	No.	95,348	96,311	963	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	779	751	(28)	4
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	1	1	–	4
56	All	Capacitor Banks	Capacitors including controls	No	3	3	–	4
57	All	Load Control	Centralised plant	Lot	21	15	(6)	4
58	All	Load Control	Relays	No	2,292	2,291	(1)	2
59	All	Civils	Cable Tunnels	km			–	N/A

Company Name	Aurora Energy Limited
For Year Ended	31 March 2023
Network / Sub-network Name	Dunedin Sub-network

SCHEDULE 9a: ASSET REGISTER

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

sch ref

	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
8								
9	All	Overhead Line	Concrete poles / steel structure	No.	18,168	18,501	333	4
10	All	Overhead Line	Wood poles	No.	11,033	10,676	(357)	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	14	14	0	3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	25	25	(0)	3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	16	16	(0)	3
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	11	11	(0)	3
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km			–	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km			–	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km			–	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km			–	N/A
22	HV	Subtransmission Cable	Subtransmission submarine cable	km			–	N/A
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	21	21	–	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.			–	N/A
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.			–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	76	82	6	4
29	HV	Zone substation switchgear	33kV RMU	No.			–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	3	3	–	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	19	19	–	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	244	244	–	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	1	1	–	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	34	34	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	722	721	(1)	4
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km			–	N/A
37	HV	Distribution Line	SWER conductor	km	9	9	(0)	4
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	52	54	2	3
39	HV	Distribution Cable	Distribution UG PILC	km	275	273	(1)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	5	5	–	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	15	15	–	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	6	6	–	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	2,849	2,868	19	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	299	272	(27)	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	398	413	15	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	1,675	1,674	(1)	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	987	993	6	4
48	HV	Distribution Transformer	Voltage regulators	No.	2	2	–	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	350	345	(5)	4
50	LV	LV Line	LV OH Conductor	km	811	809	(2)	4
51	LV	LV Cable	LV UG Cable	km	305	310	5	4
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	683	682	(1)	4
53	LV	Connections	OH/UG consumer service connections	No.	57,147	57,511	364	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	581	542	(39)	4
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	1	1	–	4
56	All	Capacitor Banks	Capacitors including controls	No	3	3	–	4
57	All	Load Control	Centralised plant	Lot	18	12	(6)	4
58	All	Load Control	Relays	No	1,125	1,122	(3)	2
59	All	Civils	Cable Tunnels	km			–	N/A

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**
Network / Sub-network Name	**Central Otago and Wanaka Sub-network**

SCHEDULE 9a: ASSET REGISTER

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

sch ref

	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
8	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
9	All	Overhead Line	Concrete poles / steel structure	No.	9,593	10,217	624	4
10	All	Overhead Line	Wood poles	No.	10,200	9,583	(617)	4
11	All	Overhead Line	Other pole types	No.			–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	310	309	(0)	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km			–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	9	9	1	3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km			–	N/A
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km			–	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	0	0	–	3
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km			–	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km			–	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km			–	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km			–	N/A
22	HV	Subtransmission Cable	Subtransmission submarine cable	km			–	N/A
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	9	10	1	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.	14	14	–	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.			–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	50	52	2	4
29	HV	Zone substation switchgear	33kV RMU	No.	1	1	–	4
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.			–	N/A
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	21	26	5	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	48	50	2	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	11	13	2	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	19	20	1	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1,271	1,271	(0)	4
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km			–	N/A
37	HV	Distribution Line	SWER conductor	km			–	N/A
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	493	515	22	3
39	HV	Distribution Cable	Distribution UG PILC	km	60	58	(2)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km			–	N/A
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	27	30	3	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.			–	N/A
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	3,333	3,396	63	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	88	88	–	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	247	266	19	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	1,853	1,860	7	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	1,433	1,476	43	4
48	HV	Distribution Transformer	Voltage regulators	No.	18	22	4	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.			–	N/A
50	LV	LV Line	LV OH Conductor	km	176	174	(1)	4
51	LV	LV Cable	LV UG Cable	km	490	510	20	4
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	244	248	4	4
53	LV	Connections	OH/UG consumer service connections	No.	23,042	23,580	538	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	120	131	11	4
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	–		–	N/A
56	All	Capacitor Banks	Capacitors including controls	No	–		–	N/A
57	All	Load Control	Centralised plant	Lot	2	2	–	4
58	All	Load Control	Relays	No	693	698	5	2
59	All	Civils	Cable Tunnels	km			–	N/A

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**
Network / Sub-network Name	**Queenstown Sub-network**

SCHEDULE 9a: ASSET REGISTER

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

sch ref

	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
8								
9	All	Overhead Line	Concrete poles / steel structure	No.	1,719	1,872	153	4
10	All	Overhead Line	Wood poles	No.	2,961	2,806	(155)	4
11	All	Overhead Line	Other pole types	No.	–		–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	70	69	(0)	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–		–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	13	13	0	3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–		–	N/A
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–		–	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–		–	N/A
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.	5	5	–	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.	–		–	N/A
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–		–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	19	19	–	4
29	HV	Zone substation switchgear	33kV RMU	No.	–		–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	6	6	–	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	12	12	–	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	40	40	–	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	10	10	–	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	14	14	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	285	284	(1)	4
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–		–	N/A
37	HV	Distribution Line	SWER conductor	km	–		–	N/A
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	203	209	6	3
39	HV	Distribution Cable	Distribution UG PILC	km	82	81	(1)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	–		–	N/A
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	13	13	–	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–		–	N/A
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	982	986	4	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	121	120	(1)	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	242	254	12	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	456	457	1	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	834	843	9	4
48	HV	Distribution Transformer	Voltage regulators	No.	8	8	–	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–		–	N/A
50	LV	LV Line	LV OH Conductor	km	46	45	(1)	4
51	LV	LV Cable	LV UG Cable	km	311	315	5	4
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	140	141	1	4
53	LV	Connections	OH/UG consumer service connections	No.	15,016	15,220	204	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	78	78	–	4
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	–	–	–	N/A
56	All	Capacitor Banks	Capacitors including controls	No	–	–	–	N/A
57	All	Load Control	Centralised plant	Lot	1	1	–	4
58	All	Load Control	Relays	No	469	471	2	2
59	All	Civils	Cable Tunnels	km			–	N/A

Company Name	Aurora Energy Limited
For Year Ended	31 March 2023
Network / Sub-network Name	Total Network

SCHEDULE 9b: ASSET AGE PROFILE

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

sch ref

8 **Disclosure Year (year ended)**

Number of assets at disclosure year end by installation date

9	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	No. with age unknown	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.		17	1,489	6,003	4,300	2,922	1,638	98	72	119	151	127	63	105	168	173	158	112	130	344	538	446	729	647	968	2,252	1,495	1,083	1,299	1,715	1,229				30,590		4
11	All	Overhead Line	Wood poles	No.	636	654	1,289	5,190	3,868	3,058	2,759	290	221	220	378	283	300	233	285	289	268	351	342	243	141	91	103	95	132	640	195	139	139	151	82				23,065		4
12	All	Overhead Line	Other pole types	No.																																			–		N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	58	3	62	119	74	38	124	0					0		6		1	6	11		0	0	3	2		1	1	0	1	11	0				522		4
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km																																			–		N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km						1	7					0	1	1	0	1	2	1	0	0	1	4		1	0	3	10		0	1	1				36		3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km					22	3																													25		3
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km				16																															16		3
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km			8		0	0	1	0		0	0	0	1		0	0				0															11		3
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km																																			–		N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km																																			–		N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km																																			–		N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km																																			–		N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km																																			–		N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.		1	4	3	8	7	4											1	1			1	1	1	1	1	1				1				36		4
25	HV	Zone substation Buildings	Zone substations 110kV+	No.																																			–		N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.																																			–		N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.												3							1				2	1			7								14		4
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.																																			–		N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.			38	18	4	23	14	1				1		2			15		2			18		1			2		2	6	6				153		4
30	HV	Zone substation switchgear	33kV RMU	No.																													1						1		4
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.							6																				3								9		4
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.					5	7	10			1	1		2		3	4	1	2		3	2	3			1	1			2	5	4				57		4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.			46	36	62	24	26				11	17		10		8		19	20	12	2	10	6	5			16		2		2				334		4
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.					3		2	1			4	2		4					1	1					1		1		1	2	1				24		4
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.			4	11	12	6	6	1		1	3	1	1			1		2	4	1	2	1	1	2			2	1	3	1	1				68		4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	53	90	245	397	386	358	333	12	11	15	7	10	30	9	12	7	9	13	13	6	8	7	15	22	10	13	11	27	30	78	39				2,276		4
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km																																			–		N/A
38	HV	Distribution Line	SWER conductor	km			4	0	0	0	0																0								4				9		4
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km				0	6	10	62	12	24	25	30	54	32	38	51	34	21	15	14	9	10	29	40	40	27	30	34	28	39	36	29				778		3
40	HV	Distribution Cable	Distribution UG PILC	km	0	8	34	48	69	72	66	6	6	9	13	6	9	11	15	5	8	9	7	5	3	4	1	1	0	0	0		0	0	0				413		3
41	HV	Distribution Cable	Distribution Submarine Cable	km		1																												3					5		4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionaliser	No.						1	1					2	3		4	6	9	1	1		2			7	1	3		1	8	5	3				58		4
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.			3		2														1																6		4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	2	14	75	483	468	608	1,016	131	115	127	145	167	130	147	127	137	134	141	147	100	123	117	168	156	129	233	284	286	359	478	503				7,250		4
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.				57	46	56	61	7	3	19	21	16	25	17	32	18	27	23	11	12	15	3	2	1	1	2	2	1			2				480		3
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.				1	36	59	116	10	18	17	40	10	26	23	18	22	24	17	20	24	13	18	17	33	39	30	56	59	65	64	58				933		3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.		4	26	204	341	477	866	105	87	99	106	98	77	73	66	72	74	55	53	55	77	62	81	62	40	86	90	110	142	147	156				3,991		4
48	HV	Distribution Transformer	Ground Mounted Transformer	No.				36	159	180	438	59	94	95	117	150	173	161	143	119	126	55	82	61	65	85	102	104	96	97	111	101	112	99	92				3,312		4
49	HV	Distribution Transformer	Voltage regulators	No.					1										3		4	5			3		4						3	2	7				32		4
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.				1	105	95	120	8	2	4	1		2	1		1			1			1	1					1			1				345		4
51	LV	LV Line	LV OH Conductor	km	51	40	103	232	212	159	172	5	4	3	4	5	3	3	2	2	2	3	2	1	2	2	2	1	1	1	1	2	2	1	4				1,028		4
52	LV	LV Cable	LV UG Cable	km	0	0	1	22	43	159	157	19	21	25	41	48	51	44	46	40	36	22	14	20	15	20	23	28	32	33	41	40	30	34	31				1,136		4
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	13	11	32	140	152	242	287	7	7	8	9	10	10	7	10	11	9	9	7	10	7	7	4	12	8	11	9	8	4	4	6				1,071		4
54	LV	Connections	OH/UG consumer service connections	No.	12,300	3,511	6,828	8,621	7,073	4,476	21,731	1,012	953	1,204	1,374	1,564	1,568	1,737	1,521	1,647	1,216	1,087	998	877	1,017	1,104	1,211	1,249	1,650	1,496	1,523	1,407	1,562	1,346	1,312			136	96,311		4
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.			147	92	60	30	48			7	18	25	3	22		2		43	5	15	6	25	7	10	2	9	41	13	59	30	28			4	751		4
56	All	SCADA and communications	SCADA and communications equipment operating as a single sys	Lot																											1								1		4
57	All	Capacitor Banks	Capacitors including controls	No																				3															3		4
58	All	Load Control	Centralised plant	Lot			2	3	4												1	1	3				1												15		4
59	All	Load Control	Relays	No		1	2	39	80	105	252	24	44	43	58	101	133	116	112	85	62	30	27	28	16	22	9	511	236	27	26	38	29	17	18				2,291		2
60	All	Civils	Cable Tunnels	km																																			–		N/A

Company Name	Aurora Energy Limited
For Year Ended	31 March 2023
Network / Sub-network Name	Dunedin Sub-network

SCHEDULE 9b: ASSET AGE PROFILE

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

sch ref

8 **Disclosure Year (year ended)**

Number of assets at disclosure year end by installation date

9	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	No. with age unknown	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.		2	1,406	5,641	2,737	1,976	753	21	11	41	54	23	16	22	29	19	16	25	27	78	154	168	311	292	531	1,049	887	611	554	608	439				18,501		4
11	All	Overhead Line	Wood poles	No.	636	634	1,207	2,219	928	1,141	1,493	171	154	116	112	87	114	101	108	141	129	89	81	101	62	36	21	19	37	490	105	61	42	21	20				10,676		4
12	All	Overhead Line	Other pole types	No.																																			–		N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	49		51	28	3		2																							11					144		4
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km																																			–		N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km																0			0	0		3		0	0	3	6		0	0					14		3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km					22	3																													25		3
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km				16																															16		3
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km			8		0	0	1	0		0	0	0	1		0	0				0															11		3
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km																																			–		N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km																																			–		N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km																																			–		N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km																																			–		N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km																																			–		N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.		1	4	3	6	4	1																			1	1								21		4
25	HV	Zone substation Buildings	Zone substations 110kV+	No.																																			–		N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.																																			–		N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.																																			–		N/A
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.																																			–		N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.			25	18	4		5												2			18					2		2	6					82		4
30	HV	Zone substation switchgear	33kV RMU	No.																																			–		N/A
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.																											3								3		4
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.					4						1				3	4				3	2									2					19		4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.			46	36	62	17	13					17		9				11	17								16								244		4
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.																														1					1		4
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.			3	9	10	2	2									1			2		2						2			1					34		4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1	16	81	238	126	70	64	5	4	8	3	4	5	5	2	5	5	5	1	1	0	2	2	0	0	0	0	14	9	34	9				721		4
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km																																			–		N/A
38	HV	Distribution Line	SWER conductor	km			4	0	0	0	0																0								4				9		4
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km				0	0	0	4	1	1	2	2	2	2	3	3	1	1	0	2	1	1	1	1	2	4	2	2	4	3	5	2				54		3
40	HV	Distribution Cable	Distribution UG PILC	km	0	8	34	48	69	48	29	2	1	1	1	1	2	3	1	1	3	3	6	3	3	3	1	1	0	0	0		0	0	0				273		3
41	HV	Distribution Cable	Distribution Submarine Cable	km		1																												3					5		4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionaliser	No.															3		3		1					4		1		1	1	1					15		4
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.			3		2														1																6		4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1	11	47	412	329	327	421	15	16	17	28	36	30	54	34	24	22	20	22	17	25	33	35	44	43	64	75	135	140	223	168				2,868		4
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.				57	46	56	44	5		9	4	6		3	2	4	9	1	6	5	10	2				1	1	1							272		3
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.				1	36	56	79	8	7	3	8	5	12	5	3	3	9	7	10	8	9	9	8	8	15	4	12	14	25	28	21				413		3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.			2	145	190	239	419	40	27	27	39	27	30	34	25	20	16	16	13	17	20	16	28	14	19	26	24	40	43	67	51				1,674		4
48	HV	Distribution Transformer	Ground Mounted Transformer	No.				36	144	130	206	16	10	16	21	15	20	36	18	12	21	14	21	20	16	19	19	24	25	27	15	32	29	12	19				993		4
49	HV	Distribution Transformer	Voltage regulators	No.					1																								1						2		4
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.				1	105	95	120	8	2	4	1		2	1		1			1			1	1					1			1				345		4
51	LV	LV Line	LV OH Conductor	km	48	25	65	169	169	141	149	4	3	2	3	4	3	2	2	1	1	2	2	0	2	1	1	1	1	0	1	1	1	1	3				809		4
52	LV	LV Cable	LV UG Cable	km	0	0	1	22	42	34	39	4	3	4	5	8	8	13	11	7	8	8	4	8	7	8	7	7	8	8	7	8	9	8	5				310		4
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	13	6	18	115	136	106	219	3	3	2	4	3	4	2	3	3	4	6	4	6	4	3	2	5	4	2	1	1	1	1	1				682		4
54	LV	Connections	OH/UG consumer service connections	No.	12,300	3,511	6,828	8,617	7,065	4,471	4,834	311	283	246	358	485	433	528	506	538	362	429	373	378	365	378	414	364	444	426	452	426	467	429	475			15	57,511		4
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.			147	92	54	3	19					22		12		2		28	1			20		4	2	2	27	13	46	27	19			2	542		4
56	All	SCADA and communications	SCADA and communications equipment operating as a single sys	Lot																											1								1		4
57	All	Capacitor Banks	Capacitors including controls	No																				3															3		4
58	All	Load Control	Centralised plant	Lot			2	3	4														3																12		4
59	All	Load Control	Relays	No		1	2	35	62	56	92	6	2	4	4	4	2	3	5	6	7	5	5	14	4	4	4	501	227	13	5	14	20	6	9				1,122		2
60	All	Civils	Cable Tunnels	km																																			–		N/A

Company Name		Aurora Energy Limited
For Year Ended		31 March 2023
Network / Sub-network Name		Central Otago and Wanaka Sub-network

SCHEDULE 9b: ASSET AGE PROFILE

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

sch ref

8 **Disclosure Year (year ended)**

Number of assets at disclosure year end by installation date

sch ref	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	No. with age unknown	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
9																																									
10	All	Overhead Line	Concrete poles / steel structure	No.		15	83	328	1,351	726	694	64	46	68	79	90	38	70	123	125	127	83	75	214	374	252	374	330	388	1,003	511	416	668	876	626				10,217		4
11	All	Overhead Line	Wood poles	No.		16	81	2,536	2,245	1,328	855	86	44	83	240	153	151	101	148	101	99	216	219	106	50	51	71	68	80	120	61	61	74	98	41				9,583		4
12	All	Overhead Line	Other pole types	No.																																			–		N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	9		9	67	59	34	103	0							4			6	11			0	2	2		1	1	0	1	0	0				309		4
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km																																			–		N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km						1	1					0	0	1	0			1				0		1			3		0	0	0				9		3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km																																			–		N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km																																			–		N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km							0																												0		3
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km																																			–		N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km																																			–		N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km																																			–		N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km																																			–		N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km																																			–		N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.					1	2	1												1			1	1	1	1						1				10		4
25	HV	Zone substation Buildings	Zone substations 110kV+	No.																																			–		N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.																																			–		N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.												3							1				2	1			7								14		4
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.																																			–		N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.			13			19	9	1				1		2										1							6				52		4
30	HV	Zone substation switchgear	33kV RMU	No.																													1						1		4
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.																																			–		N/A
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.						7	4			1			1				1					3			1				2	2	4				26		4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.						7					11			1		8			3		2	3	6	5					2		2				50		4
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.					1		1	1			4	2													1				1	1	1				13		4
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.			1	1	1	2	1			1	3	1							1			1	1	2					3		1				20		4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	41	72	156	118	246	198	187	5	5	6	2	6	24	1	6	1	3	6	11	2	8	6	12	22	4	11	10	13	20	43	25				1,271		4
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km																																			–		N/A
38	HV	Distribution Line	SWER conductor	km																																			–		N/A
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km				0	5	8	32	7	14	14	20	34	17	22	35	17	15	10	8	7	9	28	34	32	15	23	22	18	28	22	21				515		3
40	HV	Distribution Cable	Distribution UG PILC	km	0				0	12	15	2	3	3	3	3	5	2	6	1	0	2	0	1	0	0									0				58		3
41	HV	Distribution Cable	Distribution Submarine Cable	km																																			–		N/A
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.						1	1					2	1		1	6	4	1			1			2	1	2			1	3	3				30		4
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.																																			–		N/A
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1	3	26	62	122	223	405	76	61	68	89	95	70	67	65	92	80	90	101	60	83	81	119	95	71	142	175	123	178	208	265				3,396		4
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.							7	1		8	5	2	11	1	14	2	11	10	2	6	3		1	1	1		1				1				88		3
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.						1	15	1	4	8	11	1	9	4	6	6	3	6	6	8	3	6	4	11	8	16	26	30	26	24	23				266		3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.		4	22	50	129	192	324	45	43	53	55	55	37	34	34	43	40	25	34	34	46	43	45	40	18	51	57	61	94	68	84				1,860		4
48	HV	Distribution Transformer	Ground Mounted Transformer	No.					9	33	122	18	48	45	55	75	93	71	82	60	68	28	28	28	38	56	76	57	50	57	62	51	57	56	53				1,476		4
49	HV	Distribution Transformer	Voltage regulators	No.																	2	5			3		4						2	2	4				22		4
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.																																			–		N/A
51	LV	LV Line	LV OH Conductor	km	3	14	30	50	30	17	17	1	1	0	1	1	1	1	1	0	1	1	0	0	0	0	0	0	0	0	0	1	1	0	1				174		4
52	LV	LV Cable	LV UG Cable	km					1	71	64	5	8	13	17	22	29	21	17	22	15	11	6	8	5	9	11	16	17	18	27	22	15	20	20				510		4
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	1	5	10	20	11	86	34	2	2	5	2	3	4	4	3	7	5	2	2	3	3	3	2	3	3	4	4	6	2	2	4				248		4
54	LV	Connections	OH/UG consumer service connections	No.				3	5	4	10,674	342	322	490	570	606	588	590	582	699	542	366	343	279	347	417	506	611	757	698	673	650	652	611	581			72	23,580		4
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.					6	16	3			4	16	3		10				4	4		6		7	6		7	13		13	2	9			2	131		4
56	All	SCADA and communications	SCADA and communications equipment operating as a single sys	Lot																																			–		N/A
57	All	Capacitor Banks	Capacitors including controls	No																																			–		N/A
58	All	Load Control	Centralised plant	Lot																	1						1												2		4
59	All	Load Control	Relays	No				4	12	31	89	7	21	23	29	56	78	66	68	42	38	16	10	8	9	13	5	6	7	7	14	21	3	8	7				698		2
60	All	Civils	Cable Tunnels	km																																			–		N/A

Company Name	Aurora Energy Limited
For Year Ended	31 March 2023
Network / Sub-network Name	Queenstown Sub-network

SCHEDULE 9b: ASSET AGE PROFILE

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

sch ref

8 **Disclosure Year (year ended)**

Number of assets at disclosure year end by installation date

sch ref	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	No. with age unknown	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.				34	212	220	191	13	15	10	18	14	9	13	16	29	15	4	28	52	10	26	44	25	49	200	97	56	77	231	164				1,872		4
11	All	Overhead Line	Wood poles	No.		4	1	435	695	589	411	33	23	21	26	43	35	31	29	47	40	46	42	36	29	4	11	8	15	30	29	17	23	32	21				2,806		4
12	All	Overhead Line	Other pole types	No.																																			–		N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km		3	2	24	12	4	19						0		2		1				0		1							0	0				69		4
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km																																			–		N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km							5						1	0	0	1	2	0		0	1						1			0	0				13		3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km																																			–		N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km																																			–		N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km																																			–		N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km																																			–		N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km																																			–		N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km																																			–		N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km																																			–		N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km																																			–		N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.					1	1	2											1																	5		4
25	HV	Zone substation Buildings	Zone substations 110kV+	No.																																			–		N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.																																			–		N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.																																			–		N/A
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.																																			–		N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.						4											15																		19		4
30	HV	Zone substation switchgear	33kV RMU	No.																																			–		N/A
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.							6																												6		4
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.					1		6						1					2								1				1					12		4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.							13											8		12		7													40		4
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.					2		1							4					1	1							1								10		4
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.				1	1	2	3	1					1					2	1	1								1							14		4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	11	2	8	41	14	91	82	2	2	1	1	0	0	3	4	2	1	3	1	3	0		1	0	5	1	0	0	1	0	5				284		4
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km																																			–		N/A
38	HV	Distribution Line	SWER conductor	km																																			–		N/A
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km						2	27	4	9	9	7	18	12	12	14	15	5	4	4	2	1	1	5	6	8	5	11	6	7	9	6				209		3
40	HV	Distribution Cable	Distribution UG PILC	km					0	12	21	3	2	5	10	1	2	5	8	3	5	4	0	0	0	0		0	0										81		3
41	HV	Distribution Cable	Distribution Submarine Cable	km																																			–		N/A
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionaliser	No.													2				2				1			1					6	1					13		4
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.																																			–		N/A
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.			2	9	17	58	190	40	38	42	28	36	30	26	28	21	32	31	24	23	15	3	14	17	15	27	34	28	41	47	70				986		4
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.							10	1	3	2	12	8	14	13	16	12	7	12	3	1	2	1	1			1					1				120		3
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.						2	22	1	7	6	21	4	5	14	9	13	12	4	4	8	1	3	5	14	16	10	18	15	14	12	14				254		3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.			2	9	22	46	123	20	17	19	12	16	10	5	7	9	18	14	6	4	11	3	8	8	3	9	9	9	5	12	21				457		4
48	HV	Distribution Transformer	Ground Mounted Transformer	No.					6	17	110	25	36	34	41	60	60	54	43	47	37	13	33	13	11	10	7	23	21	13	34	18	26	31	20				843		4
49	HV	Distribution Transformer	Voltage regulators	No.															3		2														3				8		4
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.																																			–		N/A
51	LV	LV Line	LV OH Conductor	km		1	8	13	13	2	6	0	0	1	0	0	0	0		0	0		0	0	0	0	0	0		0		0			0				45		4
52	LV	LV Cable	LV UG Cable	km				0	1	54	53	10	10	8	18	18	13	10	18	11	13	3	5	5	3	3	4	6	6	7	7	11	7	6	6				315		4
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km			4	5	5	51	34	2	2	1	2	5	2	1	4	1	0	1	1	1	1	0		4	1	4	4	1	1	1	1				141		4
54	LV	Connections	OH/UG consumer service connections	No.				1	3	1	6,223	359	348	468	446	473	547	619	433	410	312	292	282	220	305	309	291	274	449	372	398	331	443	306	256			49	15,220		4
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.						11	26			3	2		3					11		15		5					1			1					78		4
56	All	SCADA and communications	SCADA and communications equipment operating as a single sys	Lot																																			–		N/A
57	All	Capacitor Banks	Capacitors including controls	No																																			–		N/A
58	All	Load Control	Centralised plant	Lot																		1																	1		4
59	All	Load Control	Relays	No					6	18	71	11	21	16	25	41	53	47	39	37	17	9	12	6	3	5		4	2	7	7	3	6	3	2				471		2
60	All	Civils	Cable Tunnels	km																																			–		N/A

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**
Network / Sub-network Name	**Total Network**

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref				
9				
10	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**
11	> 66kV	–	–	–
12	50kV & 66kV	127	3	130
13	33kV	396	86	482
14	SWER (all SWER voltages)	9	–	9
15	22kV (other than SWER)	–	–	–
16	6.6kV to 11kV (inclusive—other than SWER)	2,276	1,195	3,471
17	Low voltage (< 1kV)	1,028	1,136	2,164
18	**Total circuit length (for supply)**	3,836	2,420	6,256
19				
20	Dedicated street lighting circuit length (km)	531	540	1,071
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			58
22				
23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**	
24	Urban	1,158	30%	
25	Rural	2,590	68%	
26	Remote only	–	–	
27	Rugged only	88	2%	
28	Remote and rugged	–	–	
29	Unallocated overhead lines	–	–	
30	**Total overhead length**	3,836	100%	
31				
32		**Circuit length (km)**	**(% of total circuit length)**	
33	Length of circuit within 10km of coastline or geothermal areas (where known)	1,469	23%	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	3,836	100%	

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**
Network / Sub-network Name	**Dunedin Sub-network**

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref

9				
10	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**
11	> 66kV	–	–	–
12	50kV & 66kV	–	–	–
13	33kV	144	66	210
14	SWER (all SWER voltages)	9	–	9
15	22kV (other than SWER)	–	–	–
16	6.6kV to 11kV (inclusive—other than SWER)	721	332	1,053
17	Low voltage (< 1kV)	809	310	1,119
18	**Total circuit length (for supply)**	1,683	708	2,391
19				
20	Dedicated street lighting circuit length (km)	459	223	682
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			3
22				
23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**	
24	Urban	967	57%	
25	Rural	707	42%	
26	Remote only	–	–	
27	Rugged only	9	1%	
28	Remote and rugged	–	–	
29	Unallocated overhead lines	–	–	
30	**Total overhead length**	1,683	100%	
31				
32		**Circuit length (km)**	**(% of total circuit length)**	
33	Length of circuit within 10km of coastline or geothermal areas (where known)	1,469	61%	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	1,683	100%	

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**
Network / Sub-network Name	**Central Otago and Wanaka Sub-network**

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref				
9				
10	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**
11	> 66kV	–	–	–
12	50kV & 66kV	127	3	130
13	33kV	182	7	189
14	SWER (all SWER voltages)	–	–	–
15	22kV (other than SWER)	–	–	–
16	6.6kV to 11kV (inclusive—other than SWER)	1,271	573	1,844
17	Low voltage (< 1kV)	174	510	684
18	**Total circuit length (for supply)**	1,754	1,093	2,847
19				
20	Dedicated street lighting circuit length (km)	57	191	248
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			32
22				
23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**	
24	Urban	126	7%	
25	Rural	1,573	90%	
26	Remote only	–	–	
27	Rugged only	55	3%	
28	Remote and rugged	–	–	
29	Unallocated overhead lines	–	–	
30	**Total overhead length**	1,754	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	1,754	100%	

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**
Network / Sub-network Name	**Queenstown 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

sch ref		Overhead (km)	Underground (km)	Total circuit length (km)
9				
10	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**
11	> 66kV	–	–	–
12	50kV & 66kV	–	–	–
13	33kV	69	13	82
14	SWER (all SWER voltages)	–	–	–
15	22kV (other than SWER)	–	–	–
16	6.6kV to 11kV (inclusive—other than SWER)	284	290	574
17	Low voltage (< 1kV)	45	315	360
18	**Total circuit length (for supply)**	398	618	1,016
19				
20	Dedicated street lighting circuit length (km)	15	126	141
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			22
22				

sch ref		Circuit length (km)	(% of total overhead length)
23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**
24	Urban	65	16%
25	Rural	310	78%
26	Remote only	–	–
27	Rugged only	23	6%
28	Remote and rugged	–	–
29	Unallocated overhead lines	–	–
30	**Total overhead length**	398	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	398	100%

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**

SCHEDULE 9d: REPORT ON EMBEDDED NETWORKS

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

sch ref

	Location *	Average number of ICPs in disclosure year	Line charge revenue ($000)
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**
Network / Sub-network Name	**Total Network**

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref

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

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

sch ref	Consumer types defined by EDB*	Number of connections (ICPs)
10		
11	Residential	993
	Load Group 0	6
	Load Group 0A	23
	Load Group 1A	6
	Load Group 1	35
	Load Group 2	196
	Load Group 3	7
	Load Group 3A	5
12	Load Group 4	6
13	Load Group 5	–
14	Street Lighting	–
15	Distributed Unmetered Load (excl. Street Lighting)	1
16	** include additional rows if needed*	
17	**Connections total**	1,278
18		

19 *Number of ICPs decommissioned during year by consumer type*

sch ref	Consumer types defined by EDB*	Number of decommissionings
20		
21	Residential	100
	Load Group 0	5
	Load Group 0A	13
	Load Group 1A	14
	Load Group 1	32
	Load Group 2	29
	Load Group 3	1
	Load Group 3A	–
22	Load Group 4	–
23	Load Group 5	–
24	Street Lighting	–
25	Distributed Unmetered Load (excl. Street Lighting)	–
26	** include additional rows if needed*	
27	**Decommissionings total**	194
28		

sch ref			
29	**Distributed generation**		
30	Number of connections made in year	484	connections
32	Capacity of distributed generation installed in year	2.51	MVA
33			

34 **9e(ii): System Demand**

sch ref			Demand at time of maximum coincident demand (MW)
35			
36			
37		**Maximum coincident system demand**	
38		GXP demand	261
39	*plus*	Distributed generation output at HV and above	48
40		**Maximum coincident system demand**	309
41	*less*	Net transfers to (from) other EDBs at HV and above	1
42		**Demand on system for supply to consumers' connection points**	309

sch ref			Energy (GWh)	
43		**Electricity volumes carried**		
44		Electricity supplied from GXPs	1,170	
45	*less*	Electricity exports to GXPs	33	
46	*plus*	Electricity supplied from distributed generation	301	
47	*less*	Net electricity supplied to (from) other EDBs	3	
48		**Electricity entering system for supply to consumers' connection points**	1,435	
49	*less*	Total energy delivered to ICPs	1,355	
51		**Electricity losses (loss ratio)**	79	5.5%
52				
53		**Load factor**	0.53	

54 **9e(iii): Transformer Capacity**

sch ref		(MVA)
55		
56	Distribution transformer capacity (EDB owned)	957
57	Distribution transformer capacity (Non-EDB owned, estimated)	68

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**
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).

58	**Total distribution transformer capacity**	1,025
59		
60	**Zone substation transformer capacity**	1,010
61		

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**
Network / Sub-network Name	**Dunedin Sub-network**

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref			
8	**9e(i): Consumer Connections and Decommissionings**		
9	*Number of ICPs connected during year by consumer type*		
10	*Consumer types defined by EDB**	**Number of connections (ICPs)**	
11	Residential	372	
12	Load Group 0	–	
	Load Group 0A	6	
	Load Group 1A	3	
	Load Group 1	3	
	Load Group 2	44	
	Load Group 3	5	
	Load Group 3A	2	
	Load Group 4	1	
13	Load Group 5	–	
14	Street Lighting	–	
15	Distributed Unmetered Load (excl. Street Lighting)	1	
16	** include additional rows if needed*		
17	**Connections total**	437	
18			
19	*Number of ICPs decommissioned during year by consumer type*		
20	*Consumer types defined by EDB**	**Number of decommissionings**	
21	Residential	59	
	Load Group 0	1	
	Load Group 0A	5	
	Load Group 1A	11	
	Load Group 1	17	
	Load Group 2	18	
	Load Group 3	–	
	Load Group 3A	–	
22	Load Group 4	–	
23	Load Group 5	–	
24	Street Lighting	–	
25	Distributed Unmetered Load (excl. Street Lighting)	–	
26	** include additional rows if needed*		
27	**Decommissionings total**	111	
28			
29	**Distributed generation**		
30	Number of connections made in year	86	**connections**
32	Capacity of distributed generation installed in year	0.42	**MVA**
33			
34	**9e(ii): System Demand**		
35			
36			
37	**Maximum coincident system demand**	**Demand at time of maximum coincident demand (MW)**	
38	GXP demand	163	
39	*plus* Distributed generation output at HV and above	26	
40	**Maximum coincident system demand**	189	
41	*less* Net transfers to (from) other EDBs at HV and above	–	
42	**Demand on system for supply to consumers' connection points**	189	
43	**Electricity volumes carried**	**Energy (GWh)**	
44	Electricity supplied from GXPs	693	
45	*less* Electricity exports to GXPs	0	
46	*plus* Electricity supplied from distributed generation	131	
47	*less* Net electricity supplied to (from) other EDBs	–	
48	**Electricity entering system for supply to consumers' connection points**	824	
49	*less* Total energy delivered to ICPs	783	
51	**Electricity losses (loss ratio)**	42	5.1%
52			
53	**Load factor**	0.50	
54	**9e(iii): Transformer Capacity**		
55		**(MVA)**	
56	Distribution transformer capacity (EDB owned)	485	
57	Distribution transformer capacity (Non-EDB owned, estimated)	42	

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**
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).

Total distribution transformer capacity	528
Zone substation transformer capacity	586

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**
Network / Sub-network Name	**Central Otago and Wanaka Sub-network**

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref

8 ### 9e(i): Consumer Connections and Decommissionings

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

sch ref	*Consumer types defined by EDB**	Number of connections (ICPs)
10		
11	Residential	438
	Load Group 0	3
	Load Group 0A	18
	Load Group 1A	–
	Load Group 1	27
	Load Group 2	96
	Load Group 3	1
	Load Group 3A	4
12	Load Group 4	2
13	Load Group 5	–
14	Street Lighting	–
15	Distributed Unmetered Load (excl. Street Lighting)	–
16	** include additional rows if needed*	
17	**Connections total**	589
18		

19 *Number of ICPs decommissioned during year by consumer type*

sch ref	*Consumer types defined by EDB**	Number of decommissionings
20		
21	Residential	24
	Load Group 0	–
	Load Group 0A	2
	Load Group 1A	2
	Load Group 1	11
	Load Group 2	5
	Load Group 3	1
	Load Group 3A	–
22	Load Group 4	–
23	Load Group 5	–
24	Street Lighting	–
25	Distributed Unmetered Load (excl. Street Lighting)	–
26	** include additional rows if needed*	
27	**Decommissionings total**	45
28		

sch ref			
29	**Distributed generation**		
30	Number of connections made in year	294	**connections**
32	Capacity of distributed generation installed in year	1.49	**MVA**
33			

34 ### 9e(ii): System Demand

35

sch ref			Demand at time of maximum coincident demand (MW)
36			
37		**Maximum coincident system demand**	
38		GXP demand	50
39	*plus*	Distributed generation output at HV and above	18
40		**Maximum coincident system demand**	68
41	*less*	Net transfers to (from) other EDBs at HV and above	1
42		**Demand on system for supply to consumers' connection points**	67

sch ref			Energy (GWh)	
43		**Electricity volumes carried**		
44		Electricity supplied from GXPs	218	
45	*less*	Electricity exports to GXPs	33	
46	*plus*	Electricity supplied from distributed generation	155	
47	*less*	Net electricity supplied to (from) other EDBs	4	
48		**Electricity entering system for supply to consumers' connection points**	335	
49	*less*	Total energy delivered to ICPs	313	
51		**Electricity losses (loss ratio)**	23	6.8%
52				
53		**Load factor**	0.58	

54 ### 9e(iii): Transformer Capacity

sch ref		(MVA)
55		
56	Distribution transformer capacity (EDB owned)	295
57	Distribution transformer capacity (Non-EDB owned, estimated)	20

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**
Network / Sub-network Name	**Central Otago and Wanaka 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).

58	**Total distribution transformer capacity**	315
59		
60	**Zone substation transformer capacity**	260
61		

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**
Network / Sub-network Name	**Queenstown 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 and Decommissionings

sch ref			Number of connections (ICPs)
8		**9e(i): Consumer Connections and Decommissionings**	
9		*Number of ICPs connected during year by consumer type*	
10		*Consumer types defined by EDB**	
11		Residential	178
		Load Group 0	3
		Load Group 0A	(1)
		Load Group 1A	3
		Load Group 1	5
		Load Group 2	56
		Load Group 3	1
		Load Group 3A	(1)
12		Load Group 4	3
13		Load Group 5	–
14		Street Lighting	–
15		Distributed Unmetered Load (excl. Street Lighting)	–
16		** include additional rows if needed*	
17		**Connections total**	247
18			

sch ref			Number of decommissionings
19		*Number of ICPs decommissioned during year by consumer type*	
20		*Consumer types defined by EDB**	
21		Residential	17
		Load Group 0	4
		Load Group 0A	5
		Load Group 1A	1
		Load Group 1	4
		Load Group 2	6
		Load Group 3	–
		Load Group 3A	–
22		Load Group 4	–
23		Load Group 5	–
24		Street Lighting	–
25		Distributed Unmetered Load (excl. Street Lighting)	–
26		** include additional rows if needed*	
27		**Decommissionings total**	37
28			

sch ref				
29		**Distributed generation**		
30		Number of connections made in year	104	**connections**
32		Capacity of distributed generation installed in year	0.60	**MVA**
33				

9e(ii): System Demand

sch ref			Demand at time of maximum coincident demand (MW)
34		**9e(ii): System Demand**	
35			
36			
37		**Maximum coincident system demand**	
38		GXP demand	62
39	*plus*	Distributed generation output at HV and above	2
40		**Maximum coincident system demand**	64
41	*less*	Net transfers to (from) other EDBs at HV and above	–
42		**Demand on system for supply to consumers' connection points**	64

sch ref			Energy (GWh)	
43		**Electricity volumes carried**		
44		Electricity supplied from GXPs	259	
45	*less*	Electricity exports to GXPs	–	
46	*plus*	Electricity supplied from distributed generation	15	
47	*less*	Net electricity supplied to (from) other EDBs	–	
48		**Electricity entering system for supply to consumers' connection points**	274	
49	*less*	Total energy delivered to ICPs	260	
51		**Electricity losses (loss ratio)**	15	5.3%
52				
53		**Load factor**	0.49	

9e(iii): Transformer Capacity

sch ref			(MVA)
54		**9e(iii): Transformer Capacity**	
55			
56		Distribution transformer capacity (EDB owned)	176
57		Distribution transformer capacity (Non-EDB owned, estimated)	5

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**
Network / Sub-network Name	**Queenstown 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).

Total distribution transformer capacity	182
Zone substation transformer capacity	164

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**
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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

8 **10(i): Interruptions**

sch ref		Number of interruptions
9	**Interruptions by class**	
10	Class A (planned interruptions by Transpower)	–
11	Class B (planned interruptions on the network)	1,059
12	Class C (unplanned interruptions on the network)	853
13	Class D (unplanned interruptions by Transpower)	6
14	Class E (unplanned interruptions of EDB owned generation)	–
15	Class F (unplanned interruptions of generation owned by others)	–
16	Class G (unplanned interruptions caused by another disclosing entity)	–
17	Class H (planned interruptions caused by another disclosing entity)	–
18	Class I (interruptions caused by parties not included above)	1
19	**Total**	1,919
20		

sch ref		≤3Hrs	>3hrs
21	**Interruption restoration**		
22	Class C interruptions restored within	596	257
23			

sch ref		SAIFI	SAIDI
24	**SAIFI and SAIDI by class**		
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.60	174.1
27	Class C (unplanned interruptions on the network)	2.48	156.3
28	Class D (unplanned interruptions by Transpower)	0.13	13.0
29	Class E (unplanned interruptions of EDB owned generation)	–	–
30	Class F (unplanned interruptions of generation owned by others)	–	–
31	Class G (unplanned interruptions caused by another disclosing entity)	–	–
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	0.00	0.2
34	**Total**	3.21	343.7
35			

sch ref		Normalised SAIFI	Normalised SAIDI
36	**Normalised SAIFI and SAIDI**		
37	Classes B & C (interruptions on the network)	3.08	330.5
38			

sch ref		SAIFI	SAIDI
39	**Transitional SAIDI and SAIDI (previous method)**		
40	*Where EDBs do not currently record their SAIFI and SAIDI values using the ‘multi-count’ approach, they shall continue to record their SAIFI and SAIDI values on the same basis that they employed as at 31 March 2023 as ‘Transitional SAIFI’ and ‘Transitional SAIDI’ values, in addition to their SAIFI and SAIDI values (Classes B & C) using the ‘multi-count approach’.* ***This is a transitional reporting requirement that shall be in place for the 2024, 2025, and 2026 disclosure years.***		
41	Class B (planned interruptions on the network)		
42	Class C (unplanned interruptions on the network)		
43			

Company Name	Aurora Energy Limited
For Year Ended	31 March 2023
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 this 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	1.1
Vegetation	0.29	24.0
Adverse weather	0.06	12.3
Adverse environment	0.01	0.0
Third party interference	0.15	10.7
Wildlife	0.02	1.3
Human error	0.39	17.0
Defective equipment	0.94	58.2
Cause unknown	0.59	31.7

Breakdown of third party interference	SAIFI	SAIDI
Dig-in		
Overhead contact		
Vandalism		
Vehicle damage		
Other		

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.00	1.9
Subtransmission cables	0.00	0.5
Subtransmission other	0.00	0.7
Distribution lines (excluding LV)	0.41	124.5
Distribution cables (excluding LV)	0.15	36.3
Distribution other (excluding LV)	0.03	10.3

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.13	9.4
Subtransmission cables	0.02	1.3
Subtransmission other	0.26	20.5
Distribution lines (excluding LV)	1.33	93.7
Distribution cables (excluding LV)	0.15	8.7
Distribution other (excluding LV)	0.58	22.7

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	16	523	3.06
Subtransmission cables	1	89	1.12
Subtransmission other	12		
Distribution lines (excluding LV)	243	2,285	10.63
Distribution cables (excluding LV)	32	1,195	2.68
Distribution other (excluding LV)	199		
Total	503		

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**
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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

8	**10(i): Interruptions**		
9	**Interruptions by class**	**Number of interruptions**	
10	Class A (planned interruptions by Transpower)	–	
11	Class B (planned interruptions on the network)	500	
12	Class C (unplanned interruptions on the network)	284	
13	Class D (unplanned interruptions by Transpower)	–	
14	Class E (unplanned interruptions of EDB owned generation)	–	
15	Class F (unplanned interruptions of generation owned by others)	–	
16	Class G (unplanned interruptions caused by another disclosing entity)	–	
17	Class H (planned interruptions caused by another disclosing entity)	–	
18	Class I (interruptions caused by parties not included above)	1	
19	**Total**	785	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	205	79
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.44	117.9
27	Class C (unplanned interruptions on the network)	0.97	65.1
28	Class D (unplanned interruptions by Transpower)	–	–
29	Class E (unplanned interruptions of EDB owned generation)	–	–
30	Class F (unplanned interruptions of generation owned by others)	–	–
31	Class G (unplanned interruptions caused by another disclosing entity)	–	–
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	0.00	0.3
34	**Total**	1.40	183.3
35			
36	**Normalised SAIFI and SAIDI**	**Normalised SAIFI**	**Normalised SAIDI**
37	Classes B & C (interruptions on the network)	N/A	N/A
38			
39	**Transitional SAIDI and SAIDI (previous method)**	**SAIFI**	**SAIDI**
40	*Where EDBs do not currently record their SAIFI and SAIDI values using the 'multi-count' approach, they shall continue to record their SAIFI and SAIDI values on the same basis that they employed as at 31 March 2023 as 'Transitional SAIFI' and 'Transitional SAIDI' values, in addition to their SAIFI and SAIDI values (Classes B & C) using the 'multi-count approach'.* ***This is a transitional reporting requirement that shall be in place for the 2024, 2025, and 2026 disclosure years.***		
41	Class B (planned interruptions on the network)		
42	Class C (unplanned interruptions on the network)		
43			

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**
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 this 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	–	–
Vegetation	0.20	17.3
Adverse weather	0.04	3.8
Adverse environment	0.01	0.0
Third party interference	0.07	2.8
Wildlife	0.01	0.7
Human error	0.08	7.3
Defective equipment	0.41	24.8
Cause unknown	0.15	8.4

Breakdown of third party interference	SAIFI	SAIDI
Dig-in		
Overhead contact		
Vandalism		
Vehicle damage		
Other		

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	–	–
Subtransmission cables	0.00	0.8
Subtransmission other	0.00	0.4
Distribution lines (excluding LV)	0.29	86.7
Distribution cables (excluding LV)	0.11	18.9
Distribution other (excluding LV)	0.03	11.1

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.08	1.6
Subtransmission cables	–	–
Subtransmission other	0.05	6.0
Distribution lines (excluding LV)	0.56	41.8
Distribution cables (excluding LV)	0.07	3.2
Distribution other (excluding LV)	0.20	12.5

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	1	144	0.69
Subtransmission cables	–	66	–
Subtransmission other	6		
Distribution lines (excluding LV)	83	730	11.37
Distribution cables (excluding LV)	17	332	5.12
Distribution other (excluding LV)	66		
Total	173		

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**
Network / Sub-network Name	**entral Otago and Wanaka Sub-networ**

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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

8 ## 10(i): Interruptions

sch ref		Number of interruptions
9	**Interruptions by class**	
10	Class A (planned interruptions by Transpower)	–
11	Class B (planned interruptions on the network)	408
12	Class C (unplanned interruptions on the network)	380
13	Class D (unplanned interruptions by Transpower)	–
14	Class E (unplanned interruptions of EDB owned generation)	–
15	Class F (unplanned interruptions of generation owned by others)	–
16	Class G (unplanned interruptions caused by another disclosing entity)	–
17	Class H (planned interruptions caused by another disclosing entity)	–
18	Class I (interruptions caused by parties not included above)	–
19	**Total**	788
20		

sch ref		≤3Hrs	>3hrs
21	**Interruption restoration**		
22	Class C interruptions restored within	260	120
23			

sch ref		SAIFI	SAIDI
24	**SAIFI and SAIDI by class**		
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.88	272.9
27	Class C (unplanned interruptions on the network)	5.18	309.5
28	Class D (unplanned interruptions by Transpower)	–	–
29	Class E (unplanned interruptions of EDB owned generation)	–	–
30	Class F (unplanned interruptions of generation owned by others)	–	–
31	Class G (unplanned interruptions caused by another disclosing entity)	–	–
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	–	–
34	**Total**	6.06	582.4
35			

sch ref		Normalised SAIFI	Normalised SAIDI
36	**Normalised SAIFI and SAIDI**		
37	Classes B & C (interruptions on the network)	N/A	N/A
38			

sch ref		SAIFI	SAIDI
39	**Transitional SAIDI and SAIDI (previous method)**		
40	*Where EDBs do not currently record their SAIFI and SAIDI values using the 'multi-count' approach, they shall continue to record their SAIFI and SAIDI values on the same basis that they employed as at 31 March 2023 as 'Transitional SAIFI' and 'Transitional SAIDI' values, in addition to their SAIFI and SAIDI values (Classes B & C) using the 'multi-count approach'.* ***This is a transitional reporting requirement that shall be in place for the 2024, 2025, and 2026 disclosure years.***		
41	Class B (planned interruptions on the network)		
42	Class C (unplanned interruptions on the network)		
43			

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**
Network / Sub-network Name	**entral Otago and Wanaka Sub-networ**

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 this ID determination), and so is subject to the assurance report required by section 2.8.

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

Cause	SAIFI	SAIDI
Lightning	0.00	0.3
Vegetation	0.16	13.3
Adverse weather	0.12	37.1
Adverse environment	0.00	0.0
Third party interference	0.29	23.6
Wildlife	0.05	3.8
Human error	1.05	37.1
Defective equipment	2.10	125.5
Cause unknown	1.41	68.8

Breakdown of third party interference	SAIFI	SAIDI
Dig-in		
Overhead contact		
Vandalism		
Vehicle damage		
Other		

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.02	7.8
Subtransmission cables	–	–
Subtransmission other	0.01	0.7
Distribution lines (excluding LV)	0.63	190.3
Distribution cables (excluding LV)	0.19	64.8
Distribution other (excluding LV)	0.04	9.2

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.21	27.9
Subtransmission cables	–	–
Subtransmission other	0.71	52.2
Distribution lines (excluding LV)	2.67	181.7
Distribution cables (excluding LV)	0.36	15.5
Distribution other (excluding LV)	1.23	32.2

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	10	309	3.24
Subtransmission cables	–	10	–
Subtransmission other	3		
Distribution lines (excluding LV)	118	1,271	9.28
Distribution cables (excluding LV)	6	573	1.05
Distribution other (excluding LV)	101		
Total	238		

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**
Network / Sub-network Name	**Queenstown 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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

8 ### 10(i): Interruptions

sch ref	Interruptions by class	Number of interruptions
10	Class A (planned interruptions by Transpower)	–
11	Class B (planned interruptions on the network)	151
12	Class C (unplanned interruptions on the network)	189
13	Class D (unplanned interruptions by Transpower)	6
14	Class E (unplanned interruptions of EDB owned generation)	–
15	Class F (unplanned interruptions of generation owned by others)	–
16	Class G (unplanned interruptions caused by another disclosing entity)	–
17	Class H (planned interruptions caused by another disclosing entity)	–
18	Class I (interruptions caused by parties not included above)	–
19	**Total**	346
20		

sch ref	Interruption restoration	≤3Hrs	>3hrs
22	Class C interruptions restored within	131	58
23			

sch ref	SAIFI and SAIDI by class	SAIFI	SAIDI
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.81	236.6
27	Class C (unplanned interruptions on the network)	4.06	268.0
28	Class D (unplanned interruptions by Transpower)	0.86	83.1
29	Class E (unplanned interruptions of EDB owned generation)	–	–
30	Class F (unplanned interruptions of generation owned by others)	–	–
31	Class G (unplanned interruptions caused by another disclosing entity)	–	–
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	–	–
34	**Total**	5.73	587.7
35			

sch ref	Normalised SAIFI and SAIDI	Normalised SAIFI	Normalised SAIDI
37	Classes B & C (interruptions on the network)	N/A	N/A
38			

39 **Transitional SAIDI and SAIDI (previous method)**

40 *Where EDBs do not currently record their SAIFI and SAIDI values using the 'multi-count' approach, they shall continue to record their SAIFI and SAIDI values on the same basis that they employed as at 31 March 2023 as 'Transitional SAIFI' and 'Transitional SAIDI' values, in addition to their SAIFI and SAIDI values (Classes B & C) using the 'multi-count approach'.* ***This is a transitional reporting requirement that shall be in place for the 2024, 2025, and 2026 disclosure years.***

sch ref		SAIFI	SAIDI
41	Class B (planned interruptions on the network)		
42	Class C (unplanned interruptions on the network)		
43			

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2023**
Network / Sub-network Name	**Queenstown 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 this 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	0.17	6.7
Vegetation	0.83	66.4
Adverse weather	0.09	6.2
Adverse environment	–	–
Third party interference	0.26	21.1
Wildlife	–	–
Human error	0.55	22.8
Defective equipment	1.16	81.8
Cause unknown	0.99	62.9

Breakdown of third party interference	SAIFI	SAIDI
Dig-in		
Overhead contact		
Vandalism		
Vehicle damage		
Other		

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.00	0.1
Subtransmission cables	–	–
Subtransmission other	0.01	1.5
Distribution lines (excluding LV)	0.55	167.6
Distribution cables (excluding LV)	0.23	58.6
Distribution other (excluding LV)	0.03	8.8

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.20	10.6
Subtransmission cables	0.15	8.2
Subtransmission other	0.36	27.0
Distribution lines (excluding LV)	2.19	155.9
Distribution cables (excluding LV)	0.14	19.1
Distribution other (excluding LV)	1.01	47.2

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	5	69	7.25
Subtransmission cables	1	13	7.69
Subtransmission other	3		
Distribution lines (excluding LV)	42	284	14.79
Distribution cables (excluding LV)	9	290	3.10
Distribution other (excluding LV)	32		
Total	92		

Company Name	Aurora Energy Limited
For Year Ended	31 March 2023

Schedule 14 Mandatory Explanatory Notes

(Guidance Note: This Microsoft Word version of Schedules 14, 14a and 15 is from the Electricity Distribution Information Disclosure Determination 2012 – as amended and consolidated 3 April 2018. Clause references in this template are to that determination)

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 11 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.

4. Return on Investment (Schedule 2)

5. 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 RY23 return on investment (ROI) exceeded the estimated WACC used to set Aurora Energy's price path. The RY23 ROI is above the 75th percentile of WACC, that has been estimated by the Commerce Commission for Information Disclosure purposes. The main driver of these results has been the increase in RAB revaluations.

Aurora Energy is subject to an incremental rolling incentive scheme (IRIS) under price-quality regulation. The IRIS seeks to incentivise EDBs to control expenditure by penalising the EDB if it exceeds expenditure allowances, determined by the Commerce Commission, and rewarding it if expenditure is below the allowance.

The opex IRIS incentive for RY23 is a positive adjustment of $13.0m that relates to operational expenditure allowances in the previous regulatory period. The capex IRIS incentive for RY23 is a penalty of $1.5m for overspending capital expenditure allowances in the previous regulatory period. These incentives were included in Aurora Energy's calculation of allowable revenue when setting prices for RY23.

IRIS allowances are a designated recoverable cost in price-quality regulation and are therefore recovered through pass-through prices, rather than distribution prices. Consistent with our Pricing Methodology we have allocated the IRIS incentive to pricing areas and load groups in proportion to last year's revenue recoveries in those areas and groups . Aurora Energy consider this is the most equitable way of allocating the incentive – customers who paid greater charges in the past, when Aurora Energy's expenditure allowances were being exceeded, should receive a greater share of the money being returned.

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

Regulatory Profit (Schedule 3)

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

   6.1 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

   6.2 information on reclassified items in accordance with subclause 2.7.1(2).

Box 2: Explanatory comment on regulatory profit

Regulatory profit for the year to 31 March 2023 is $60.0m before tax. This represents a $18.1m increase from the previous year. The increase was largely driven by higher line revenue (+$17.3m), and revaluations (+$5.4m) that was largely offset by higher depreciation (+$3.3m) and operational expenses (+$2.0m).

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

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

   7.1 information on reclassified items in accordance with subclause 2.7.1(2)

   7.2 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)

8. 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 regulatory asset base (RAB) increased by $90.8m during the year (compared with $105.6m in RY22). A decrease of $14.8m on the prior disclosure year's RAB increase. The drivers of the decrease were lower commissioned assets (-$16.1m), higher depreciation (+$3.3m) and disposals (+$0.8m) which were partially offset by an increase in revaluations (+$5.4m). The asset category transfer of $0.2m between distribution and low voltage lines and subtransmission lines relates to a correction of RY22 disposals.

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

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

   9.1 Income not included in regulatory profit / (loss) before tax but taxable;

   9.2 Expenditure or loss in regulatory profit / (loss) before tax but not deductible;

   9.3 Income included in regulatory profit / (loss) before tax but not taxable;

   9.4 Expenditure or loss deductible but not in regulatory profit / (loss) before tax.

Box 5: Regulatory tax allowance: permanent differences

The amount of $34,936 relating to 'Expenditure or loss in regulatory profit or (loss) before tax but not deductible' is non-deductible entertainment. The amount of $1,131,279 relating to 'Expenditure or loss deductible but not in regulatory profit / (loss) before tax' relates to payments for leases that are classified as ROU assets.

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

10. 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)

Temporary timing differences of $1,944,770 recorded in the current disclosure year relate to the tax effect of income spreading over 10 years on capital initiated works ($1,949,307), downward movement in provision for expected credit losses (doubtful debts) ($21,000) and increase in employee entitlements ($16,463).

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

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 7: Cost allocation

All operational expenditure is 100% directly attributable to the regulated business.

No items have been 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 8: Commentary on asset allocation

Other network assets includes a fibre network that comprises of ducting / high speed broadband fibre utilised for communications between the Dunedin zone substation sites. It is assessed that for RY23, 75.5% of the network is utilised for communications between the Dunedin zone substation sites (compared to 75.5% in RY22).

No items have been 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 9: Explanation of capital expenditure for the disclosure year

Aurora Energy's Asset Management Plan contains the 10-year expenditure forecasts relating to capital expenditure projects and programmes of work to be undertaken in each regulatory year. The projects and programmes are grouped by the regulatory expenditure categories of consumer connection, system growth, asset replacement and renewal, asset relocations, reliability, safety and environment and non-network capex.

Consumer connection capital expenditure, disclosed in 6a(iii), is inclusive of all connections. Insufficient data is currently captured to align that expenditure with consumer load groups. The listed projects within this schedule are the higher value projects included within the specific reporting categories.

No items have been 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, a including the value of the expenditure the purpose of the expenditure, and the operational expenditure categories the expenditure relates to.

Box 10: Explanation of operational expenditure for the disclosure year

RY23 operational expenditure was \$48.3m in line with forecast expenditure.

RY23 network maintenance was \$0.5m above the forecast of \$20.2m. Offset by a \$1.9m underspend on service interruptions and emergencies. Corrective and preventative maintenance was \$2.2m above the forecast, and vegetation management ended the year \$0.2m above forecast.

RY23 non-network operational expenditure was \$0.5m below the forecast of \$28.1m. Components of the underspend included:

- System operations and network support (SONS) expenditure was \$0.6m below the forecast, inclusive of underspends in network evolution (-\$0.3m), and other system operating and support costs (-\$0.3m),
- Business support expenditure was \$0.1m below forecast, inclusive of overspends in IT (+0.4m) and other business support costs (+\$0.1m) offset by underspend in administration and governance (-\$0.4m).

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

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 11: Explanatory comment on variance in actual to forecast expenditure

Overall, Aurora Energy's total asset expenditure was $6.5m (7%) higher than forecast.

Consumer connection growth reflects the continuing higher levels of development activity on the network, mainly on the Central Otago/Wanaka and Queenstown subnetworks. This is also impacting system growth expenditure.

The asset replacement and renewal expenditure was within 3% of forecast for the year.

Total reliability, safety, and environment was higher than forecast due to additional expenditure relating to new generators at the Omakau and Camp Hill substations to provide additional load during peak times.

Non-network capital expenditure was lower than expected largely due to a delay in our asset management system project.

Service interruptions and emergencies expenditure was below forecast due to lower levels of reactive maintenance work than expected.

We increased expenditure from forecast for corrective maintenance inspections to improve our asset information.

Vegetation management was within 4% of forecast for the year.

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 12: Explanatory comment relating to revenue for the disclosure year

Total Revenue:

The forecast revenue from line charges was $121.8m.

In Schedule 8 (Total Network) total line charge revenue of $123.2m is reported. This is a difference of $1.4m (1.1%) above forecast. It is generally expected that total billed line charge revenue for a regulatory year will be different to forecast revenue due to variation in connection numbers and energy demand.

Residential Revenue:

The volume of energy delivered to residential consumers (the only consumer groups with volume-based pricing) increased from the prior year (by 1.8%). Energy delivered to residential connections was 629.6 GWh compared to 618.6 GWh for RY22.

The average number of residential connections increased by 1.1% during the regulatory year. The average number of residential connections was 78,946, compared with 78,090 for RY22.

The average energy use per residential consumer is 7,975 kWh compared to 7,921 kWh for RY22.

General Revenue:

The average number of general connections, which are priced predominantly on the basis of demand and capacity is 15,365 compared to 15,186 for RY22.

The distinction between Residential and General connections is explained in section 4 of Aurora Energy's Use-of-System Pricing Methodology, available from

http://www.auroraenergy.co.nz/disclosures/pricing/pricing-methodologies

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 13: Commentary on network reliability for the disclosure year

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

- Overhead (subtransmission and distribution) includes poles, stay-wires, crossarms, braces, insulators, conductor (including droppers and connectors), binders and ties.
- Underground (subtransmission and distribution) includes cable, mounting brackets, terminations and potheads.
- Other (subtransmission and distribution) includes HV fuses (including fuse operation), lightning 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. This, in our view, meets the broad definition of "Fault" given in the Determination – "a physical condition that causes a device, component or network element to fail to perform in the required manner".

Specific commentary on matters relating to Aurora Energy's reliability performance for the disclosure year is contained in Aurora Energy's Annual Compliance Statement (2023), available from https://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 14: Explanation of insurance cover

Insurance cover is in place for zone substations for the buildings, plant and equipment contained within them. The material damage (including flood, earthquake etc.) cover for the zone substations and associated equipment is on a replacement cost basis. Material damage insurance cover has been obtained for some distribution assets including distribution substations, transformers, and switches.

Other distribution assets including distribution poles, lines and cables etc. are not currently insured due to the unavailability of commercial policy terms, 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 15: Disclosure of amendment to previously disclosed information

There have been no amendments to previously disclosed information.

Company Name Aurora Energy Limited

For Year Ended 31 March 2023

Schedule 15 Voluntary Explanatory Notes

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012 – as amended and consolidated 3 April 2018.)

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

Information disclosure exemption: Disclose and auditing of reliability information

Aurora Energy, along with all other EDBs, received an exemption from the Commerce Commission, issued on 26 May 2023, regarding the disclosure and auditing of reliability information within Schedule 10. The information in this box is disclosed in accordance with paragraph 11 of that exemption.

Treatment of successive interruptions between disclosure years 2022 and 2023: We have treated successive interruptions in the same way for the 2023 disclosure year as we did for the 2022 disclosure year.

Process applied in recognising successive interruptions following an initial outage: We have recognised any stage of an outage event that interrupts consumers for a second time, or interrupts 'new' consumers as a result of fault finding, as an additional interruption, strictly in line with the definition of "interruption" included in the Electricity Distribution Information Disclosure Determination 2012.

Sale of the Te Anau embedded network

On 1 December 2022 Aurora Energy sold its Te Anau embedded network of approximately 140 ICPs. The sale was to a regulated supplier and the value of assets disposed is disclosed in schedule 4 RAB Value (rolled Forward) section (ii).

1 Description of the connection between Aurora Energy and its related parties

Pursuant to clause 2.3.8 of the Electricity Distribution Information Disclosure Determination 2012 (Determination), the following table describes the connection between Aurora Energy and the related parties with which it has had related party transactions during the year ended 31 March 2023.

RELATED PARTY	RELATIONSHIP BETWEEN AURORA AND THE RELATED PARTY	PRINCIPAL ACTIVITIES OF THE RELATED PARTY	TOTAL ANNUAL EXPENDITURE INCURRED BY AURORA ENERGY WITH THE RELATED PARTY
Delta Utility Services Limited (Delta)	Aurora Energy and Delta are related as DCHL is the ultimate holding company of Aurora Energy and Delta. DCHL is the sole shareholder of Delta.	Delta is a multi-utility services contractor providing a range of electrical and other services to local authority and private sector clients. The principal activities of Delta are the management, construction, operation and maintenance of electricity and metering infrastructure assets, and the provision of environmental contracting and related services.	$51,506,000 This expenditure is in relation to operating and capital expenditure incurred by Aurora Energy with Delta.
Dunedin City Council (DCC)	The DCC is the sole shareholder of DCHL.	The DCC is the territorial authority for the Dunedin area in accordance with the Local Government Act 2002.	$969,000 This expenditure is primarily in relation to local rates that are payable to the DCC.
Dunedin Venues Management Limited (DVML)	Aurora Energy and DVML are related because DCHL is the ultimate holding company of Aurora Energy and DVML. DCHL is the sole shareholder of DVML.	The principal activities of DVML are to source and secure appropriate events for all venues under its management, to plan host and deliver events to a high standard, to manage the assets and facilities for which it is responsible and to facilitate community access to the venues for which it is responsible.	$1,000 This expenditure is in relation to venue hire fees.

2 Summary of Aurora Energy's current procurement policy

Pursuant to clause 2.3.10 of the Determination, the following is a summary of Aurora Energy's current policy in respect of the procurement of assets or goods or services from any related party.

2.1 Introduction

Aurora Energy is an electricity distribution business (EDB) which owns and operates electricity distribution networks in Dunedin and Central Otago (including Queenstown Lakes). We own and manage a wide range of assets that are used to transport electricity from the national grid, owned by Transpower, to end-use consumers.

Our role is to ensure the safety and resilience of the network, supplying a reliable electricity service to over 94,500 homes, farms and businesses throughout the regions we serve.

We are regulated by the Commerce Commission in relation to both the quality of the electricity we supply and the revenue that we are able to generate.

As a result of the regulated constraints within which we operate, it is important for us to ensure that our procurement practices are efficient, controlled and robust. This will result in lower costs to our business, which in turn results in lower costs to consumers in the long term. It will also ensure that we are procuring the right goods and services for our network.

This section 2 summarises briefly the procurement principles that we adopt when procuring goods and services and the procurement methods that we employ.

2.2 Procurement Principles

1. ***Plan and manage for great results:*** we take a strategic approach by considering the long-term benefits, economic impacts and consequences of procurement decisions for Aurora Energy. This means planning procurement requirements in advance, choosing the appropriate procurement method and ensuring we have appropriately skilled and experienced staff to lead procurement activities;
2. ***Be fair to all suppliers:*** we will ensure that all eligible suppliers have a fair opportunity to participate in procurements by encouraging capable suppliers to respond, treating all suppliers equally and making it easy to deal with us;
3. ***Get the right supplier:*** while we will not always choose the lowest price, we will choose the right supplier who can deliver what we need, at a fair price and on time. We need to consider safety on, and reliability of, our network, durability, specialised skills that may be required, availability of resources in the current labour market and the sustainability of suppliers on our network;
4. ***Get the best deal for everyone:*** we will seek the best possible outcome taking into account the total cost of ownership over the whole life of the asset. This means balancing financial and non-financial criteria, balancing risks with benefits, employing robust evaluation processes and working together with suppliers to make ongoing savings and improvements.
5. ***Play by the rules:*** we must ensure that we are transparent, accountable and acting at all times lawfully by being consistent, adhering to best practice, being accurate and unbiased, acting with integrity and good faith and in accordance with the law.

When procuring goods and services, we may not always choose the lowest price, instead we may, having adhered to the above principles, make robust and sound commercial decisions to ensure that we are getting the best commercial outcome.

When determining the appropriate method of procurement it is important to consider the criticality of the goods or services to be supplied and the risks or business impact of non-supply. The identification of low value, low risk goods and services versus high value, highly critical goods or services helps to inform the appropriate procurement method to use.

2.3 Procurement methods

We employ the following procurement methods in the course of our business:

- **direct procurement**: in certain circumstances it will be appropriate to procure goods and services directly from one supplier, for example where the goods and services are low in both value and risk, or where the goods and services are both high in value and risk. This may also be an appropriate method of procurement where the circumstances are unforeseen and an urgent response is required;
- **written quotations:** this is appropriate where the good or service being procured is lower in value, but higher in risk;
- **tender:** where the good or service being procured is high in both value and risk, a formal tender process (either open or selective) may be conducted). It may be necessary for tender participants to be approved by Aurora Energy to work on our distribution network, and to design and construct additions to the network;
- **panel arrangement:** for certain works, we have a panel arrangement in place with several contractors who operate on our distribution network. We adopt this approach to ensure that we are able to deliver our works programme and have the capacity and capabilities on our network to do so;
- **All-of-Government contract:** Aurora Energy is a party to several All-of-Government contracts and benefits from the bulk-purchasing power associated with those contracts; and
- **Group purchasing:** Aurora Energy is a subsidiary of Dunedin City Holdings Limited and in certain situations has the ability to use the bulk-purchasing power associated with that group.

The following table provides a representative example of the procurement methods that we employ in relation to each category of expenditure.

TYPE OF EXPENDITURE	PROCUREMENT METHODS
OPERATING EXPENDITURE	
Non-network operating expenditure: • business support • system operations and network support	• Direct procurement – low value, low risk • Written quotes • All-of-Government • Group purchasing
Network operating expenditure: • routine and corrective maintenance and inspection • vegetation management • asset replacement and renewal • service interruptions and emergencies	• Panel arrangement • Direct procurement
CAPITAL EXPENDITURE	
Customer initiated works	• Customer-led (a customer or developer may use their own contractor provided that they are an Aurora Approved Contractor).
Network and non-network capital expenditure: • system growth • reliability, safety and environment • asset replacement and renewal • asset relocations • non-system fixed assets (ie IT systems, asset management systems, office buildings and furniture, motor vehicles).	• Panel arrangement • Direct procurement • Tender • All-of-Government

3 Application of procurement policy

Pursuant to clause 2.3.12 of the Determination, the following illustrates Aurora Energy's application of its current policy in respect of the procurement of assets or goods or services from a related party.

3.1 Description of application of Aurora Energy's current procurement policy for the procurement of assets or goods or services from a related party in practice

3.1.1 Field Services Agreements

Historically, Delta undertook both asset management and service provider roles on behalf of Aurora Energy, the asset owner. Following an independent review in early 2017, our shareholder, DCHL, sought formal separation of the two businesses. From 1 July 2017, Aurora Energy became a standalone regulated asset owner and manager, with accountability for providing electricity distribution services.

The separation reinforces that Aurora Energy has a clear responsibility to seek the best available services from the market on behalf of its customers. In order to achieve this, we have introduced contestable performance based service delivery arrangements with two additional field service providers - Unison Contracting based in Dunedin, and Connetics based in Central Otago. Our new contracts with Unison and Connetics took effect from 1 April 2019. Unison Contracting and Connetics appointment as contractors on our network sees them carrying out renewal, maintenance and development work.

This new arrangement between the three contractors has been consolidated in the field services agreement (FSA) that we have entered into with each contractor. Each FSA had an initial term of three years, which provides us with an opportunity on a regular basis to refresh and test our contractual relationship. The FSAs with all providers were renewed during 2021 for a further two years, and have therefore become five year agreements.

Given our specialised needs as an electricity distributor, while we acknowledge that it is important that we are clear about our needs, we need to choose suppliers who can deliver what we need, at a fair price and on time. We need to consider the safety of both consumers and contractors on our network, our ability to provide a reliable supply of electricity to consumers on the network, specialised skills that are required to deliver the work we require, the availability of resources in the current labour market and the sustainability of specialist skill sets within our network and the viability of incumbent service providers.

Traditionally Delta has delivered a large portion of our network operational and capital expenditure works. Since the commencement of the Field Service Agreements in 2019, this was reflected in Delta being the Primary Service Provider. The Primary Service Provider performs the bulk of maintenance activity on the network, including all first response and fault repairs.

With Unison and Connetics having now established themselves as Secondary Service Providers, we need to continue to monitor the application of our procurement policies to ensure that our procurement practices remain efficient. We also need to ensure that those practices are providing the means and incentives for Unison and Connetics to offer alternative solutions and further embed themselves as long-term contractors on our network and to be able to offer Aurora Energy alternative solutions to works delivery. We also understand the need to provide Unison and Connetics with sufficient work to ensure their viability on our network.

3.1.2 External tender market

In addition to our FSA arrangements, we also operate an external tender market into which works are submitted each year and approved contractors (in addition to our FSA providers) are invited to tender. Delta, plus the other FSA providers and other approved contractors participate in this external tender market.

3.1.3 Engineering Services Consultancy Panel

We also have established an Engineering Services Consultancy Panel to provide specific electricity design services for asset replacement and renewal projects and growth projects. The panel consists of engineering consulting companies, including Delta.

3.1.4 Customer Initiated Works

Together with the other approved contractors on our network, Delta provides customer connection services at market value rates. Under our customer initiated works model, customers or developers are able to choose their own designer and builder from a panel of approved contractors operating on our network.

3.1.5 Vegetation Services Agreement

Delta has traditionally performed vegetation management services across the entire Aurora network. However, from 1 April 2022, vegetation management for the Queenstown subnetwork has been procured separately to the FSA under a specific vegetation services agreement (VSA). The term of the VSA is five years and was competitively tendered on the open market.

3.1.6 Internal controls

Internally, staff responsibilities and purchasing controls are managed by delegated financial authorities and claim verification procedures. Our procurement activities are also overseen by the Audit and Risk Committee of the Board.

Our procurement policy details the methods that we use to procure goods and services from any party, whether they be related or not, and those methods are contained in the summary at section 2 above.

3.2 Policies or procedures that require or have the effect of requiring a consumer to purchase assets or goods or services from a related party

Aurora does not have policies or procedures that require a consumer to purchase goods or services from a related party. Aurora has a selection of Approved Contractors operating on the network, from which customers can choose from.

3.3 Representative example transactions from the year ended 31 March of how the current policy for the procurement of assets or goods or services from a related party is applied in practice, including separate representative example transactions where Aurora Energy has applied the policy significantly differently between expenditure categories

EXPENDITURE CATEGORY	REPRESENTATIVE EXAMPLE	PROCUREMENT METHOD	HOW AND WHEN ARM'S LENGTH TERMS LAST TESTED
Operating expenditure			
Service interruptions and emergencies	Response to a fault on overhead network	Services were procured through the negotiated FSA	The terms upon which services are provided, and the rates at which services are charged, were tested in 2018 during the development of the three FSAs.
Vegetation management	Liaison and cutting on specified feeders in the Dunedin region	Services were procured through the negotiated FSA	The terms upon which services are provided, and the rates at which services are charged, were tested in 2018 during the development of the three FSAs.
	Liaison and cutting on specified feeders in the Queenstown region	Services were procured through the tendered VSA	The terms upon which services are provided, and the rates at which services are charged, were tested in 2021 during the tendering of the VSA.
Routine and corrective maintenance and inspection	Maintenance of switchgear	Services were procured through the negotiated FSA	The terms upon which services are provided, and the rates at which services are charged, were tested in 2018 during the development of the three FSAs.
System operations and network support	Provision of logistic services including provision of storage facilities.	Services were procured through the negotiated FSA	The terms upon which services are provided, and the rates at which services are charged, were tested in 2018 during the development of the three FSAs.
Business support	Rental of office premises	Direct procurement	Market lease rates were tested on 1 April 2022 when an independent valuation report was obtained.

EXPENDITURE CATEGORY	REPRESENTATIVE EXAMPLE	PROCUREMENT METHOD	HOW AND WHEN ARM'S LENGTH TERMS LAST TESTED
Capital expenditure			
System growth	Reinforcement of low voltage network	Services were procured through the negotiated FSA	The terms upon which services are provided, and the rates at which services are charged, were tested in 2018 during the development of the three FSAs.
	Installation of new transformer at a zonesubstation	Tender	The terms were last tested on 19 December 2022.
Asset replacement and renewal	Replacement of poles	Services were procured through the negotiated FSA.	The terms upon which services are provided, and the rates at which services are charged, were tested in 2018 during the development of the three FSAs.
	Upgrade of the protection and secondary systems at a zonesubstation	Tender	The terms were last tested on 13 January 2023.
Asset relocations	Relocation of overhead network on third party (Chorus) owned poles	Services were procured through the negotiated FSA.	The terms upon which services are provided, and the rates at which services are charged, were tested in 2018 during the development of the three FSAs.
Reliability, safety and environment	Installation of reclosers on overhead network	Services were procured through the negotiated FSA.	The terms upon which services are provided, and the rates at which services are charged, were tested in 2018 during the development of the three FSAs.
Non-network assets	Procurement of locks for assisting in ensuring the safety of people operating the network	Direct procurement	Not tested.

4 Map of anticipated network expenditure and network constraints

Pursuant to clauses 2.3.13 to 2.3.16 of the Determination, the following tables and associated maps provide detail on Aurora Energy's 10 largest operational and capital expenditure projects in the AMP planning period.

4.1 Top 10 operational and capital expenditure projects

The following tables and corresponding maps identify our largest anticipated operational and expenditure projects on our network in the AMP planning period. The legends contained on the maps of our subnetworks correspond to the project number in each table.

4.1.1 Operational expenditure projects

In relation to operational expenditure, we have four main programmes of work that affect the whole of our network:

- preventive maintenance;
- reactive maintenance;
- vegetation management; and
- corrective maintenance.

We have included details of each of these programmes in the table below and have identified, for preventive and corrective maintenance, those sub-programmes that sit within each of those that contribute to our ten largest operational expenditure programmes. Note the value of projects are expressed in nominal terms.

DESCRIPTION OF THE PROJECT (INCLUDING ANY POSSIBLE FUTURE NETWORK OR EQUIPMENT CONSTRAINT THAT THE PROJECT ADDRESSES)		LIKELY TIMING OF THE PROJECT	LIKELY VALUE OF THE PROJECT	LOCATION OF THE PROJECT	CONTRACTUAL STATUS
Operational expenditure					
1.	**Preventive Maintenance** This programme encompasses routine maintenance activities including testing, inspections, condition assessments and servicing. We have incorporated high level and lower level programmes (where possible) into the top 10 list to show visibility of high value works of similar type.	RY24-33	$88.8 million	Total network	This programme of works is covered by three FSAs, each of which have a five year term from 1 April 2019 to 31 March 2024. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers.

DESCRIPTION OF THE PROJECT (INCLUDING ANY POSSIBLE FUTURE NETWORK OR EQUIPMENT CONSTRAINT THAT THE PROJECT ADDRESSES)		LIKELY TIMING OF THE PROJECT	LIKELY VALUE OF THE PROJECT	LOCATION OF THE PROJECT	CONTRACTUAL STATUS
	We have identified our likely spend over the AMP planning period at a high programme level, while each lower level programme reflects how that expenditure is allocated in RY24.				
1a.	**Pole Inspections** This programme of works encompasses the preventive inspection of poles on the Aurora Energy network.	RY24	$1.9 million	Total network	This programme of works is covered by three FSAs, each of which have a five year term from 1 April 2019 to 31 March 2024. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers.
1b.	**RMU Preventive Maintenance** This programme of works encompasses the carrying out of preventive maintenance on Aurora Energy's RMUs.	RY24	$2.4 million	Total network	This programme of works is covered by three FSAs, each of which have a five year term from 1 April 2019 to 31 March 2024. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers.
1c.	**Zone Substation Preventive Maintenance** This programme of works encompasses the carrying out of preventive maintenance in Aurora Energy's zone substations.	RY24	$0.7 million	Total network	This programme of works is covered by three FSAs, each of which have a five year term from 1 April 2019 to 31 March 2024. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers.
1d.	**Overhead Conductor Inspections** This programme of works encompasses the carrying out of preventive inspections on Aurora Energy's overhead conductors.	RY24	$1.3 million	Total network	This programme of works is covered by three FSAs, each of which have a five year term from 1 April 2019 to 31 March 2024. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers.

DESCRIPTION OF THE PROJECT (INCLUDING ANY POSSIBLE FUTURE NETWORK OR EQUIPMENT CONSTRAINT THAT THE PROJECT ADDRESSES)		LIKELY TIMING OF THE PROJECT	LIKELY VALUE OF THE PROJECT	LOCATION OF THE PROJECT	CONTRACTUAL STATUS
1e.	**Ancillary Distribution Substation Equipment Preventative Maintenance** This programme of works encompasses the carrying out of preventive maintenance in Aurora Energy's ancillary distribution substation equipment.	RY24	$0.1 million	Total network	This programme of works is covered by three FSAs, each of which have a five year term from 1 April 2019 to 31 March 2024. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers.
1f.	**LV Enclosure Inspections** This programme of works encompasses the carrying out of preventive inspections on Aurora Energy's LV enclosures.	RY24	$0.9 million	Total network	This programme of works is covered by three FSAs, each of which have a five year term from 1 April 2019 to 31 March 2024. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers.
2.	**Reactive Maintenance** Expenditure related to unplanned interruptions to the supply of electricity through the Aurora Energy network and emergency events where a fault has occurred, require response by field-based contractors on our network.	RY24-33	$37.1 million	Total network	This programme of works is covered by three FSAs, each of which have a five year term from 1 April 2019 to 31 March 2024. One of the FSAs is with Delta, a related party. Under the FSAs, this programme of works is primarily contracted to a related party, Delta, however two other contractors on our network, to whom we are not related, are contracted to provide additional resource for service interruptions and emergencies.
3.	**Vegetation Management** Our vegetation management programme includes identification, inspection and assessment of vegetation growing near Aurora Energy's network, notification and liaison with customers	RY24-33	$43.6 million	Total network	This programme of works is covered by three FSAs, each of which have a five year term from 1 April 2019 to 31 March 2024, and the Frankton VSA, which has a term from 1 April 2022 to

	DESCRIPTION OF THE PROJECT (INCLUDING ANY POSSIBLE FUTURE NETWORK OR EQUIPMENT CONSTRAINT THAT THE PROJECT ADDRESSES)	LIKELY TIMING OF THE PROJECT	LIKELY VALUE OF THE PROJECT	LOCATION OF THE PROJECT	CONTRACTUAL STATUS
	and the carrying out of preliminary and physical works.				31 March 2027. The VSA, and one of the FSAs, is with Delta, a related party. Under the VSA and FSAs, this programme of works is contracted exclusively to Delta.
4.	**Corrective Maintenance** Primarily involves remediating defects, by replacing components or minor assets, or undertaking repairs. Corrective work may be identified during preventive maintenance or fault response. Programmes 4a and 4b below are encompassed within this category of expenditure.	RY24-33	$43.5 million	Total network	This programme of works is covered by three FSAs, each of which have a five year term from 1 April 2019 to 31 March 2024. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers.
4a.	**Possum and Cable Guard Retrofit Programme** This programme of work encompasses the retrofitting of possum guards and cable guards on the Aurora network.	RY24-26	$0.6 million	Total network	This programme of works is covered by three FSAs, each of which have a five year term from 1 April 2019 to 31 March 2024. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers.

4.1.2 Capital expenditure projects

In relation to capital expenditure, we have identified our largest programmes of work. These affect the whole of our network, however, we have identified, where relevant, the largest projects that form a part of that programme, which can be easily identified as affecting a specific part of the network. As with table 4.1.1, the value of projects are expressed in nominal terms.

	DESCRIPTION OF THE PROJECT (INCLUDING ANY POSSIBLE FUTURE NETWORK OR EQUIPMENT CONSTRAINT THAT THE PROJECT ADDRESSES)	LIKELY TIMING OF THE PROJECT	LIKELY VALUE OF THE PROJECT	LOCATION OF THE PROJECT	CONTRACTUAL STATUS
Capital expenditure					
1.	**Pole Replacement** This is an ongoing programme of work to replace poles on a condition basis. The replacements involve entire pole assemblies (with crossarms) and may include replacement of pole mounted equipment such as distribution transformers if these are also assessed as being at end of life.	RY24-33	$201.7 million	Total network	This programme of works is covered by three FSAs, each of which have a five year term from 1 April 2019 to 31 March 2024. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers, and other Approved Contractors.
2.	**Zone Substation Renewals** This is a programme of renewal projects that we plan to undertake at specific zone substations due to assets that have been identified as being in poor condition and having reached end-of-life. Items 2a through 2f describe the six most significant of these renewal projects.	RY24-33	$58.9 million	Specific zone substations located across the network	Currently not indicated for supply by a related party.
2a.	**Smith Street Substation Renewal - Transformers** The equipment contained in the Smith Street substation is near-end-of-life and requires renewal. This project involves replacing the existing transformers (two off) with 33kV/11kV 16/24MVA transformers complete with on load tap changers. Additional works include oil containment system upgrade, cabling, protection and neutral earthing resisters.	RY27-29	$4.2 million	Smith Street, Dunedin	Currently not indicated for supply by a related party.
2b.	**Mosgiel Transformer Replacement and 33 kV Outdoor-Indoor Conversion** The equipment contained in the Mosgiel substation is near-end-of-life and requires renewal. This project involves replacing the power transformers and replacing the 33 kV outdoor switchyard with a new	RY25-27	$9.0 million	Mosgiel, Dunedin	Currently not indicated for supply by a related party.

DESCRIPTION OF THE PROJECT (INCLUDING ANY POSSIBLE FUTURE NETWORK OR EQUIPMENT CONSTRAINT THAT THE PROJECT ADDRESSES)		LIKELY TIMING OF THE PROJECT	LIKELY VALUE OF THE PROJECT	LOCATION OF THE PROJECT	CONTRACTUAL STATUS
	switchroom building to house a new 33 kV switchboard.				
2c.	**Green Island Substation Rebuild** The equipment contained in the Green Island substation is near-end-of-life and requires renewal. The optimum solution is for the substation to be rebuilt on the existing site.	RY24-25	$4.3 million	Green Island, Dunedin	Currently not indicated for supply by a related party.
2d.	**Willowbank Substation Renewal** The equipment contained in the Willowbank substation is near-end-of-life and requires renewal. The optimum solution involves the replacement of the 6.6 kV switchboard and the power transformers.	RY27-29	$6.2 million	Willowbank, Dunedin	Currently not indicated for supply by a related party.
2e.	**Alexandra Substation Renewal** The equipment contained in the Alexandra substation is near-end-of-life and requires renewal. This project involves re-establishing the 11kV and 33kV switchgear in indoor buildings.	RY24	$4.2 million	Alexandra, Central Otago	Currently not indicated for supply by a related party.
2f.	**East Taieri Substation Renewal** The equipment contained in the East Taieri substation is near-end-of-life and requires renewal.	RY29-31	$5.9 million	Mosgiel, Dunedin	Currently not indicated for supply by a related party.
3.	**Crossarm Replacement** This is an ongoing programme of work to replace crossarms on a condition basis.	RY24-33	$69.9 million	Total network	This programme of works is covered by three FSAs, each of which have a five year term from 1 April 2019 to 31 March 2024. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers, and other Approved Contractors.
4.	**Distribution Conductor Replacement**	RY24-33	$37.2 million	Total network	This programme of works will likely be provided by a mix of FSAs, each of

	DESCRIPTION OF THE PROJECT (INCLUDING ANY POSSIBLE FUTURE NETWORK OR EQUIPMENT CONSTRAINT THAT THE PROJECT ADDRESSES)	LIKELY TIMING OF THE PROJECT	LIKELY VALUE OF THE PROJECT	LOCATION OF THE PROJECT	CONTRACTUAL STATUS
	This is an ongoing programme of work to replace distribution conductor that has reached end-of-life.				which have a five year term from 1 April 2019 to 31 March 2024, and competitive tender. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers, and other Approved Contractors.
5.	**Subtransmission Cable Replacements** This is a programme involving the renewal of specific subtransmission cables on our Dunedin network that are in poor condition and have reached end-of-life. Items 5a, 5b and 5c below describe three of the most significant projects.	RY24-33	$24.1 million	Dunedin	Currently not indicated for supply by a related party.
5a.	**Willowbank Cable Replacement and Switchboard** This project involves the installation of a 33 kV switchboard at the Willowbank Substation and the replacement of the existing Halfway Bush to Willowbank gas filled, PILC, underground, 33 kV cables. It forms a part of our plan to gradually transition to a meshed sub-transmission network in the Dunedin CBD.	RY31-33	$6.2 million	Willowbank, Dunedin	Currently not indicated for supply by a related party.
5b.	**Corstorphine Cable Replacement** This project involves the replacement of the existing oil filled, PILC, 33 kV underground cables that run between the South Dunedin GXP and the Corstorphine zone substation.	RY27-30	$10.0 million	Corstorphine, Dunedin	Currently not indicated for supply by a related party.
5c.	**Kaikorai Valley Cable Replacement** This project involves the replacement of the existing PILC, 33 kV underground cables that run between the Halfway Bush GXP and the Kaikorai zone substation.	RY24-26	$6.6 million	Kaikorai Valley, Dunedin	Currently not indicated for supply by a related party.

DESCRIPTION OF THE PROJECT (INCLUDING ANY POSSIBLE FUTURE NETWORK OR EQUIPMENT CONSTRAINT THAT THE PROJECT ADDRESSES)		LIKELY TIMING OF THE PROJECT	LIKELY VALUE OF THE PROJECT	LOCATION OF THE PROJECT	CONTRACTUAL STATUS
6.	**Low voltage Conductor Replacement** This is an ongoing programme of work to replace LV conductor that has reached end-of-life.	RY24-33	$24.9 million	Total network	This programme of works is covered by three FSAs, each of which have a five year term from 1 April 2019 to 31 March 2024. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers, and other Approved Contractors.
7.	**Distribution Cable Replacements** This is a programme involving the renewal of distribution cables on our Dunedin network that and have reached end-of-life.	RY24-33	$2.9 million	Total network	This programme of works is covered by three FSAs, each of which have a five year term from 1 April 2019 to 31 March 2024. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers.
8.	**Ancillary Distribution Sub Replacements** This is an ongoing programme of work to replace ancillary distribution substations that have reached end-of-life.	RY24-33	$12.6 million	Total network	This programme of works is covered by three FSAs, each of which have a five year term from 1 April 2019 to 31 March 2024. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers.
9.	**Ground Mounted Switchgear Replacements** This is an ongoing programme of work to replace ground mounted switchgear that has reached end-of-life.	RY24-33	$53.5 million	Total network	This programme of works is covered by three FSAs, each of which have a five year term from 1 April 2019 to 31 March 2024. One of the FSAs is with Delta, a related party. We expect the work to be allocated among the three FSA providers.
10.	**Pole Mounted Transformer Replacement** This is an ongoing programme of work to replace distribution transformers that have reached end-of-	RY24-33	$8.1 million	Total network	This programme of works is covered by three FSAs, each of which have a five year term from 1 April 2019 to 31 March 2024. One of the FSAs is with

DESCRIPTION OF THE PROJECT (INCLUDING ANY POSSIBLE FUTURE NETWORK OR EQUIPMENT CONSTRAINT THAT THE PROJECT ADDRESSES)	LIKELY TIMING OF THE PROJECT	LIKELY VALUE OF THE PROJECT	LOCATION OF THE PROJECT	CONTRACTUAL STATUS
life. It includes pole mount to ground mount conversions of large two pole substations, which are not seismically qualified.				Delta, a related party. We expect the work to be allocated among the three FSA providers.

4.2 Maps

4.2.1 Dunedin subnetwork

Grid Exit Point · Zone Substation · 33kV overhead line · 33kV underground cable

Operational Expenditure:

1 - 4 Total network

Capital Expenditure:

1 3 - 4 6 - 10 Total network

2a Smith St substation renewal

2b Mosgiel transformer replacement and 33 kV outdoor-indoor conversion

2c Green Island substation rebuild

2d Willowbank substation renewal

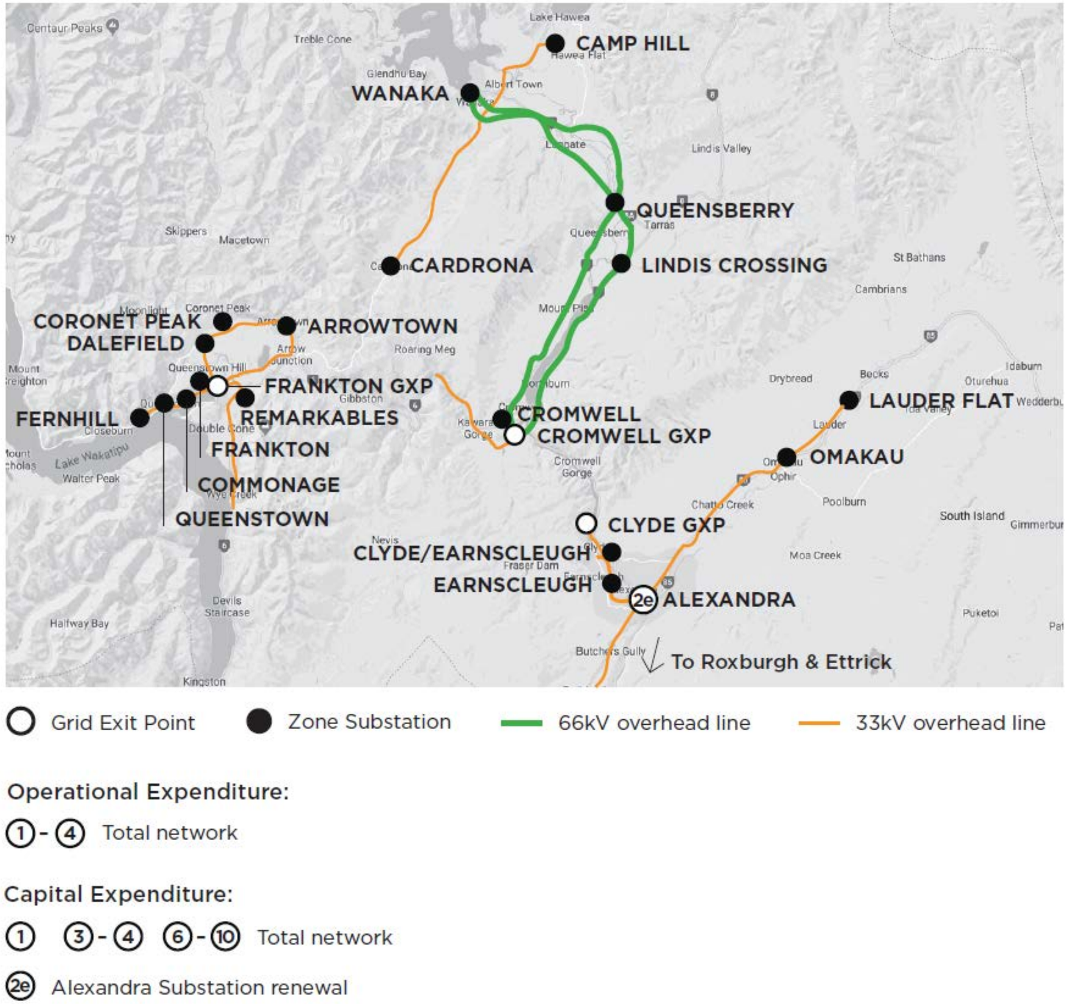
2f East Taieri substation renewal

5a Willowbank cable replacement and switchboard

5b Corstorphine cable replacement

5c Kaikorai Valley cable replacement

4.2.2 Central Otago subnetwork



SCHEDULE 18

Certification for Year-end Disclosures

Clause 2.9.2 and 2.9.5

We, Stephen Richard Thompson and Janice Evelyn Frederic, being directors of Aurora Energy Limited, 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 Aurora Energy Limited's accounting and other records sourced from its financial and non-financial systems, and that sufficient appropriate records have been retained.

c. In respect of information concerning assets, costs and revenues valued or disclosed in accordance with clause 2.3.6 of the Electricity Distribution Information Disclosure Determination 2012 and clauses 2.2.11(1)(g) and 2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012, we are satisfied that-

   i. the costs and values of assets or goods or services acquired from a related party comply, in all material respects, with clauses 2.3.6(1) and 2.3.6(3) of the Electricity Distribution Information Disclosure Determination 2012 and clauses 2.2.11(1)(g) and 2.2.11(5)(a)-2.2.11(5)(b) of the Electricity Distribution Services Input Methodologies Determination 2012; and

   ii. the value of assets or goods or services sold or supplied to a related party comply, in all material respects, with clause 2.3.6(2) of the Electricity Distribution Information Disclosure Determination 2012.

Stephen Richard Thompson

Janice Evelyn Frederic

29 August 2023

Audit New Zealand
Mana Arotake Aotearoa

Independent Assurance Report

To the directors of Aurora Energy Limited and to the Commerce Commission on the disclosure information for the disclosure year ended 31 March 2023 as required by the Electricity Distribution Information Disclosure Determination 2012 (consolidated 6 July 2023)

Aurora Energy Limited (the company) is required to disclose certain information under the Electricity Distribution Information Disclosure Determination 2012 (consolidated 6 July 2023) (the Determination) and to procure an assurance report by an independent auditor in terms of section 2.8.1 of the Determination.

The Auditor-General is the auditor of the company.

The Auditor-General has appointed me, Julian Tan, using the staff and resources of Audit New Zealand, to undertake a reasonable assurance engagement, on his behalf, on whether the information prepared by the company for the disclosure year ended 31 March 2023 (the Disclosure Information) complies, in all material respects, with the Determination.

The Disclosure Information that falls within the scope of the assurance engagement are:

- Schedules 1 to 4, 5a to 5g, 6a and 6b, 7, 10 and 14 (limited to the explanatory notes in boxes 1 to 11) of the Determination.

- Clause 2.3.6 of the Determination and clauses 2.2.11(1)(g) and 2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012 (consolidated 20 May 2020) (the IM Determination), in respect of the basis for valuation of related party transactions (the Related Party Transaction Information).

This assurance report should be read in conjunction with the Commerce Commission's Information Disclosure exemption, issued to all electricity distribution businesses on 9 June 2023 under clause 2.11.1 of the Determination. The Commerce Commission granted an exemption from the requirement that the assurance report, in respect of the information in Schedule 10 of the Determination, must take into account any issues arising out of the company's recording of SAIDI, SAIFI, and number of interruptions due to successive interruptions.

Opinion

In our opinion, in all material respects:

- as far as appears from an examination, 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, sourced from the company's financial and non-financial systems;
- the Disclosure Information complies, in all material respects, with the Determination; and
- the basis for valuation of related party transactions complies with the Determination and the IM Determination.

Basis for opinion

We conducted our engagement in accordance with the Standard on Assurance Engagements 3100 (Revised) Compliance Engagements (SAE 3100 (Revised)), issued by the New Zealand Auditing and Assurance Standards Board. An engagement conducted in accordance with SAE 3100 (Revised) requires that we comply with the International Standard on Assurance Engagements (New Zealand) 3000 (Revised) Assurance Engagements Other Than Audits or Reviews of Historical Financial Information.

We have obtained sufficient recorded evidence and explanations that we required to provide a basis for our opinion.

Key assurance matters

Key assurance matters are those matters that, in our professional judgement, required significant attention when carrying out the assurance engagement during the current disclosure year. These matters were addressed in the context of our compliance engagement, and in forming our opinion. We do not provide a separate opinion on these matters.

Key assurance matter	How our procedures addressed the key assurance matter
Capital expenditure and assets commissioned into the regulatory asset base (the RAB) The RAB, as set out in Schedule 4, reflects the value of the company's electricity distribution assets. During the disclosure year, the company has carried out a large number of individual network system projects that are either operational (network maintenance) or capital (asset	We have obtained an understanding of the compliance requirements relevant to the RAB as set out in the Determination. The procedures we carried out to satisfy ourselves that the capital expenditure and assets commissioned meet the definition under the Determination, included: • assessing the company's capitalisation policy was in line with NZ IAS 16 Property, Plant and Equipment;

Key assurance matter	How our procedures addressed the key assurance matter
replacement or network growth) in nature. Capital expenditure in the current disclosure year totalled \$87 million and assets commissioned into the RAB amounted to \$77 million, compared to total network operating expenditure of \$48 million. The amount of capital expenditure is also significant relative to the RAB opening value of \$645 million. Capital expenditure and assets commissioned into the RAB are a key assurance matter due to the significant judgement by company personnel and the auditor to assess whether the capital expenditure and assets commissioned into the RAB meets the definition set out in the Determination.	• evaluating the design and implementation of controls over the classification of the network expenditure; • testing a sample of capital expenditure to invoices or other supporting information to determine whether the expenditure met the capitalisation criteria in the Determination and capitalised to the appropriate asset category; and • reconciling the assets commissioned from the regulatory fixed asset register to the additions disclosed in the audited financial statements and investigated any reconciling items; Having completed these procedures, we have no matters to report.
Valuation of related-party transactions at arms-length The Determination and the IM Determination place a requirement on the company to value related-party procurement transactions at a value not greater than arm's-length. In other words, the value at which a transaction, with the same terms and conditions, would be entered into between a willing seller and a willing buyer who are unrelated and who are acting independently of each other and pursuing their own best interests. In the absence of an active market for related-party transactions, assignment of an objective arm's-length value to a related-party transaction is difficult. This a key assurance matter because it involves considerable judgement by company personnel. In turn, verification of the appropriate assignment of an objective arm's-length valuation to related-party transactions require the exercise of significant professional judgement by the auditor.	We obtained an understanding of the company's approach to identifying and valuing related-party transactions at arm's-length in accordance with the Determination and the IM Determination. The procedures we carried out to satisfy ourselves that related-party transactions are appropriately valued at a value not greater than arm's-length included: • testing the completeness of related-parties identified through review of Board minutes, review of Companies Office records, and related-parties identified through detailed testing of transactions and balances in the annual financial statements audit; • reviewing the relevant policies for approval and negotiation of related-party transactions, and testing compliance with those policies; • reviewing and testing the field services agreement with related parties; • benchmarking the charges against quotations from non-related parties; • confirming the material accuracy of related party values disclosed, and compliance of their calculation with the Determination and the IM Determination; and

Key assurance matter	How our procedures addressed the key assurance matter
	• confirming related party transactions valued at the cost incurred by the related party to underlying records. Having carried out these procedures, we are satisfied that related party transactions are valued at arms-length.
Accuracy of the number and duration of electricity outages The company has a combination of manual and automated systems to identify outages and to record the duration of outages. This outage information is used to report the company's Report on Network Reliability in schedule 10. If this information is inaccurate then the measures of the reliability of the network could be materially misstated. This is a key assurance matter because information on the frequency and duration of outages is an important measure of the reliability of electricity supply. Relatively small inaccuracies can have a significant impact on the reliability thresholds against which the company's performance is assessed. There can also be significant consequences if the company breaches the reliability thresholds. The Commerce Commission has issued an Exemption notice which, if it applies excludes the assurance report from coverage of the information, in schedule 10 of the ID Determination, for any issues arising out of the company's recording of SAIDI, SAIFI and number of interruptions due to successive interruptions. We need to ensure that the company meets the criteria for the Exemption to apply, including that it makes the necessary disclosures so the exclusion to the assurance opinion applies.	We obtained an understanding of the company's system to record electricity outages, and their duration. This included a review of the company's definition of interruptions, planned interruptions and major event days. The procedures we carried out to assess the adequacy of the company's methods to identify and record electricity outages and their duration included: • performing an assessment of the reliability of the manual and automated processes to record the details of interruptions to supply; • obtaining internal and external information on interruptions such as board minutes and media reports to gain assurance that interruptions to supply were recorded; • testing a sample of interruptions to supply to source records to conclude on their accuracy of calculation, and the appropriateness of the categorisation of the cause of the interruption and whether it was planned or unplanned, and that the cause of the interruptions is correctly categorised; • checked the SAIDI and SAIFI ratios were correctly calculated in accordance with the Determination, and the IM Determination; • obtained explanations for all significant variances to forecast; and • testing the accuracy of the number of connections to the Electricity Authority's register. With respect to the Exemption, we: • obtained and documented our understanding of the company's methods by which electricity outages and their duration are recorded where an outage event results in successive interruptions of supply; • compared this to the documented process that the company followed in the previous year; and • identified potential incidences of successive interruptions of supply to ensure that the

Key assurance matter	How our procedures addressed the key assurance matter
	company's methods, by which electricity outages and their duration are recorded where an outage event results in successive interruptions of supply, were the same for both years. Having carried out these procedures, and assessed the likelihood of reported electricity outages and their duration being materially misstated in the Disclosure Information, we have no matters to report.

Directors' responsibilities

The directors of the company are responsible in accordance with the Determination for:

- the preparation of the Disclosure Information; and
- the Related Party Transaction Information.

The directors of the company are also responsible for the identification of risks that may threaten compliance with the schedules and clauses identified above and controls which will mitigate those risks and monitor ongoing compliance.

Auditor's responsibilities

Our responsibilities in terms of clauses 2.8.1(1)(b)(vi) and (vii), 2.8.1(1)(c) and 2.8.1(1)(d) are to express an opinion on whether:

- as far as appears from an examination, the information used in the preparation of the audited Disclosure Information has been properly extracted from the company's accounting and other records, sourced from its financial and non-financial systems;
- as far as appears from an examination, proper records to enable the complete and accurate compilation of the audited Disclosure Information required by the Determination have been kept by the company and, if not, the records not so kept;
- the company complied, in all material respects, with the Determination in preparing the audited Disclosure Information; and
- the company's basis for valuation of related party transactions in the disclosure year has complied, in all material respects, with clause 2.3.6 of the Determination and clauses 2.2.11(1)(g) and 2.2.11(5) of the IM Determination.

To meet these responsibilities, we planned and performed procedures in accordance with SAE 3100 (Revised), to obtain reasonable assurance about whether the company has complied, in all material respects, with the Disclosure Information (which includes the Related Party Transaction Information) required to be audited by the Determination.

An assurance engagement to report on the company's compliance with the Determination involves performing procedures to obtain evidence about the compliance activity and controls implemented to meet the requirements. The procedures selected depend on our judgement, including the identification and assessment of the risks of material non-compliance with the requirements.

Inherent limitations

Because of the inherent limitations of an assurance engagement, together with the internal control structure, it is possible that fraud, error, or non-compliance with the Determination may occur and not be detected.

A reasonable assurance engagement throughout the disclosure year does not provide assurance on whether compliance with the Determination will continue in the future.

Restricted use

This report has been prepared for use by the directors of the company and the Commerce Commission in accordance with clause 2.8.1(1)(a) of the Determination and is provided solely for the purpose of establishing whether the compliance requirements have been met. We disclaim any assumption of responsibility for any reliance on this report to any person other than the directors of the company and the Commerce Commission, or for any other purpose than that for which it was prepared.

Independence and quality control

We complied with the Auditor-General's:

- independence and other ethical requirements, which incorporate the requirements of Professional and Ethical Standard 1 International Code of Ethics for Assurance Practitioners (including International Independence Standards) (New Zealand) (PES 1) issued by the New Zealand Auditing and Assurance Standards Board; and

- quality management requirements, which incorporate Professional and Ethical Standard 3 Quality Management for Firms that perform Audits or Reviews of Financial Statements, or Other Assurance or Related Services Engagements (PES 3) issued by the New Zealand Auditing and Assurance Standards Board. PES 3 requires our firm to design, implement and operate a system of quality management including policies or procedures regarding compliance with ethical requirements, professional standards, and applicable legal and regulatory requirements.

The Auditor-General, and his employees, and Audit New Zealand and its employees may deal with the company on normal terms within the ordinary course of trading activities of the company.

Other than any dealings on normal terms within the ordinary course of trading activities of the company, this engagement, the assurance engagement on the Customised Price-Quality Path, the assurance engagement on the Annual Delivery Report, and the annual audit of the company's financial statements and statement of service performance, we have no relationship with, or interests in, the company.

Julian Tan
Audit New Zealand
On behalf of the Auditor-General
Dunedin, New Zealand
30 August 2023