For the disclosure year ending 31 March 2022

INFORMATION DISCLOSURE

Aurora ENERGY

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Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**

SCHEDULE 1: ANALYTICAL RATIOS

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

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

sch ref

7 1(i): Expenditure metrics

sch ref		Expenditure per GWh energy delivered to ICPs ($/GWh)	Expenditure per average no. of ICPs ($/ICP)	Expenditure per MW maximum coincident system demand ($/MW)	Expenditure per km circuit length ($/km)	Expenditure per MVA of capacity from EDB-owned distribution transformers ($/MVA)
8						
9	**Operational expenditure**	35,393	496	149,951	7,446	49,108
10	Network	15,045	211	63,744	3,165	20,876
11	Non-network	20,348	285	86,207	4,280	28,232
12						
13	**Expenditure on assets**	65,322	915	276,752	13,742	90,635
14	Network	62,307	873	263,981	13,107	86,452
15	Non-network	3,014	42	12,771	634	4,183
16						

17 1(ii): Revenue metrics

sch ref		Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
18			
19	**Total consumer line charge revenue**	80,969	1,134
20	Standard consumer line charge revenue	72,583	1,010
21	Non-standard consumer line charge revenue	1,243,290	818,015
22			

23 1(iii): Service intensity measures

sch ref			
24			
25	Demand density	50	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
26	Volume density	210	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
27	Connection point density	15	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
28	Energy intensity	14,011	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*
29			

30 1(iv): Composition of regulatory income

sch ref		($000)	% of revenue
31			
32	Operational expenditure	46,260	44.31%
33	Pass-through and recoverable costs excluding financial incentives and wash-ups	30,915	29.61%
34	Total depreciation	22,502	21.55%
35	Total revaluations	37,128	35.56%
36	Regulatory tax allowance	1,640	1.57%
37	Regulatory profit/(loss) including financial incentives and wash-ups	40,220	38.52%
38	**Total regulatory income**	104,409	
39			

40 1(v): Reliability

sch ref			
41			
42	Interruption rate	26.28	*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 the ID Determination or if they elect to. If an EDB makes this election, information supporting this calculation must be provided in 2(iii).

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

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

sch ref					
7		**2(i): Return on Investment**	**CY-2**	**CY-1**	**Current Year CY**
8			**31 Mar 20**	**31 Mar 21**	**31 Mar 22**
9		**ROI – comparable to a post tax WACC**	**%**	**%**	**%**
10		Reflecting all revenue earned	2.23%	1.46%	6.98%
11		Excluding revenue earned from financial incentives	2.32%	4.30%	9.33%
12		Excluding revenue earned from financial incentives and wash-ups	2.44%	4.30%	9.33%
13					
14		**Mid-point estimate of post tax WACC**	4.27%	3.72%	3.52%
15		25th percentile estimate	3.59%	3.04%	2.84%
16		75th percentile estimate	4.95%	4.40%	4.20%
17					
18					
19		**ROI – comparable to a vanilla WACC**			
20		Reflecting all revenue earned	2.65%	1.79%	7.27%
21		Excluding revenue earned from financial incentives	2.74%	4.63%	9.63%
22		Excluding revenue earned from financial incentives and wash-ups	2.86%	4.63%	9.63%
23					
24		**WACC rate used to set regulatory price path**	7.19%	4.57%	4.57%
25					
26		**Mid-point estimate of vanilla WACC**	4.69%	4.05%	3.82%
27		25th percentile estimate	4.01%	3.37%	3.14%
28		75th percentile estimate	5.37%	4.73%	4.50%
29					
30		**2(ii): Information Supporting the ROI**		**($000)**	
31					
32		Total opening RAB value	539,722		
33	*plus*	Opening deferred tax	(27,147)		
34		**Opening RIV**		512,575	
35					
36		**Line charge revenue**		105,829	
37					
38		Expenses cash outflow	77,175		
39	*add*	Assets commissioned	93,006		
40	*less*	Asset disposals	2,087		
41	*add*	Tax payments	(1,500)		
42	*less*	Other regulated income	(1,420)		
43		**Mid-year net cash outflows**		168,014	
44					
45		**Term credit spread differential allowance**		–	
46					
47		Total closing RAB value	645,301		
48	*less*	Adjustment resulting from asset allocation	34		
49	*less*	Lost and found assets adjustment	–		
50	*plus*	Closing deferred tax	(30,287)		
51		**Closing RIV**		614,980	
52					
53		**ROI – comparable to a vanilla WACC**			7.27%
54					
55		Leverage (%)			42%
56		Cost of debt assumption (%)			2.55%
57		Corporate tax rate (%)			28%
58					
59		**ROI – comparable to a post tax WACC**			6.98%
60					

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

This schedule requires information on the Return on Investment (ROI) for the EDB relative to the Commerce Commission's estimates of post tax WACC and vanilla WACC. EDBs must calculate their ROI based on a monthly basis if required by clause 2.3.3 of the ID Determination or if they elect to. If an EDB makes this election, information supporting this calculation must be provided in 2(iii).

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

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sch ref

61 **2(iii): Information Supporting the Monthly ROI**

sch ref		
63	**Opening RIV**	N/A

sch ref		Line charge revenue	Expenses cash outflow	Assets commissioned	Asset disposals	Other regulated income	Monthly net cash outflows
67	April						–
68	May						–
69	June						–
70	July						–
71	August						–
72	September						–
73	October						–
74	November						–
75	December						–
76	January						–
77	February						–
78	March						–
79	**Total**	–	–	–	–	–	–

sch ref		
81	**Tax payments**	N/A
83	**Term credit spread differential allowance**	N/A
85	**Closing RIV**	N/A
88	**Monthly ROI – comparable to a vanilla WACC**	N/A
90	**Monthly ROI – comparable to a post tax WACC**	N/A

92 **2(iv): Year-End ROI Rates for Comparison Purposes**

sch ref		
94	**Year-end ROI – comparable to a vanilla WACC**	10.31%
96	**Year-end ROI – comparable to a post tax WACC**	10.01%

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

100 **2(v): Financial Incentives and Wash-Ups**

sch ref			
102	Net recoverable costs allowed under incremental rolling incentive scheme	(16,814)	
103	Purchased assets – avoided transmission charge	–	
104	Energy efficiency and demand incentive allowance		
105	Quality incentive adjustment	(614)	
106	Other financial incentives	–	
107	**Financial incentives**		(17,428)
109	**Impact of financial incentives on ROI**		–2.35%
111	Input methodology claw-back	–	
112	CPP application recoverable costs	–	
113	Catastrophic event allowance	–	
114	Capex wash-up adjustment	–	
115	Transmission asset wash-up adjustment	–	
116	2013–15 NPV wash-up allowance	–	
117	Reconsideration event allowance	–	
118	Other wash-ups	–	
119	**Wash-up costs**		–
121	**Impact of wash-up costs on ROI**		–

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

sch ref				
7		**3(i): Regulatory Profit**		**($000)**
8		**Income**		
9		Line charge revenue		105,829
10	*plus*	Gains / (losses) on asset disposals		(2,087)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)		667
12				
13		**Total regulatory income**		104,409
14		**Expenses**		
15	*less*	Operational expenditure		46,260
16				
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups		30,915
18				
19		**Operating surplus / (deficit)**		27,234
20				
21	*less*	Total depreciation		22,502
22				
23	*plus*	Total revaluations		37,128
24				
25		**Regulatory profit / (loss) before tax**		41,861
26				
27	*less*	Term credit spread differential allowance		–
28				
29	*less*	Regulatory tax allowance		1,640
30				
31		**Regulatory profit/(loss) including financial incentives and wash-ups**		40,220
32				
33		**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	**($000)**	
34		**Pass through costs**		
35		Rates	1,031	
36		Commerce Act levies	280	
37		Industry levies	345	
38		CPP specified pass through costs	1,879	
39		**Recoverable costs excluding financial incentives and wash-ups**		
40		Electricity lines service charge payable to Transpower	21,848	
41		Transpower new investment contract charges	424	
42		System operator services	–	
43		Distributed generation allowance	5,074	
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**		30,915
47				

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).
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sch ref

48	**3(iii): Incremental Rolling Incentive Scheme**		**($000)**	
49			**CY-1**	**CY**
50			**31 Mar 21**	**31 Mar 22**
51	Allowed controllable opex			
52	Actual controllable opex			
53				
54	Incremental change in year			
55				
56			**Previous years' incremental change**	**Previous years' incremental change adjusted for inflation**
57	CY-5	31 Mar 17		
58	CY-4	31 Mar 18		
59	CY-3	31 Mar 19		
60	CY-2	31 Mar 20		
61	CY-1	31 Mar 21		
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			

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

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

sch ref

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

for year ended	RAB 31 Mar 18 ($000)	RAB 31 Mar 19 ($000)	RAB 31 Mar 20 ($000)	RAB 31 Mar 21 ($000)	RAB 31 Mar 22 ($000)
Total opening RAB value	354,222	394,155	447,072	489,854	539,722
less **Total depreciation**	13,710	15,058	16,809	20,358	22,502
plus **Total revaluations**	3,878	5,824	11,277	7,402	37,128
plus **Assets commissioned**	50,335	63,004	49,227	61,073	93,006
less **Asset disposals**	570	853	912	830	2,087
plus **Lost and found assets adjustment**	–	–	–	2,581	–
plus **Adjustment resulting from asset allocation**	–	–	–	–	34
Total closing RAB value	394,155	447,072	489,854	539,722	645,301

4(ii): Unallocated Regulatory Asset Base

	Unallocated RAB * ($000)	 ($000)	RAB ($000)	 ($000)
Total opening RAB value		540,594		539,722
less				
Total depreciation		22,546		22,502
plus				
Total revaluations		37,188		37,128
plus				
Assets commissioned (other than below)	49,148		49,148	
Assets acquired from a regulated supplier	–		–	
Assets acquired from a related party	43,858		43,858	
Assets commissioned		93,006		93,006
less				
Asset disposals (other than below)	2,087		2,087	
Asset disposals to a regulated supplier	–		–	
Asset disposals to a related party	–		–	
Asset disposals		2,087		2,087
plus **Lost and found assets adjustment**		–		–
plus **Adjustment resulting from asset allocation**				34
Total closing RAB value		646,155		645,301

** 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.*

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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				1,142
55		CPI_4^{-4}				1,068
56		Revaluation rate (%)				6.93%
57						
58			**Unallocated RAB ***		**RAB**	
59			**($000)**	**($000)**	**($000)**	**($000)**
60		Total opening RAB value	540,594		539,722	
61	*less*	Opening value of fully depreciated, disposed and lost assets	3,874		3,874	
62						
63		Total opening RAB value subject to revaluation	536,720		535,848	
64		**Total revaluations**		37,188		37,128
65						

sch ref						
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**		48,751		48,750
69	*plus*	Capital expenditure	71,831		71,832	
70	*less*	Assets commissioned	93,006		93,006	
71	*plus*	Adjustment resulting from asset allocation			–	
72		**Works under construction - current disclosure year**		27,576		27,576
73						
74		Highest rate of capitalised finance applied				2.85%
75						

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

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

sch ref

76 4(v): Regulatory Depreciation

sch ref		Unallocated RAB *		RAB	
78		($000)	($000)	($000)	($000)
79	Depreciation - standard	20,292		20,292	
80	Depreciation - no standard life assets	2,254		2,210	
81	Depreciation - modified life assets	–		–	
82	Depreciation - alternative depreciation in accordance with CPP	–		–	
83	**Total depreciation**		22,546		22,502
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**	18,327	21,398	92,806	145,176	144,062	63,798	27,283	20,483	6,388	539,722
100	*less*	Total depreciation	798	653	3,593	4,783	4,749	2,358	1,437	1,923	2,210	22,502
101	*plus*	Total revaluations	1,262	1,483	6,325	9,937	9,982	4,420	1,890	1,403	426	37,128
102	*plus*	Assets commissioned	14,948	4,431	14,098	35,047	10,739	4,417	6,638	1,476	1,213	93,006
103	*less*	Asset disposals	322	–	–	1,765	–	–	–	–	–	2,087
104	*plus*	Lost and found assets adjustment	–	–	–	–	–	–	–		–	–
105	*plus*	Adjustment resulting from asset allocation	–	–	–	–	–	–	–	–	34	34
106	*plus*	Asset category transfers	–	–	–	–	–	–	–	–	–	–
107		**Total closing RAB value**	33,418	26,659	109,636	183,612	160,034	70,277	34,375	21,439	5,851	645,301
108												
109		**Asset Life**										
110		Weighted average remaining asset life	22.6	32.8	25.8	30.0	30.3	27.1	19.0	10.6	2.9	(years)
111		Weighted average expected total asset life	46.7	54.1	49.9	53.1	51.8	51.0	39.5	15.4	8.0	(years)

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SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

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

sch ref					
7	**5a(i): Regulatory Tax Allowance**				**($000)**
8		**Regulatory profit / (loss) before tax**			41,861
9					
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	11	*	
12		Amortisation of initial differences in asset values	4,956		
13		Amortisation of revaluations	2,749		
14					7,716
15					
16	*less*	Total revaluations	37,128		
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	1,170	*	
20		Notional deductible interest	5,421		
21					43,719
22					
23		**Regulatory taxable income**			5,858
24					
25	*less*	Utilised tax losses	–		
26		Regulatory net taxable income			5,858
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**			1,640
30					
31	*	Workings to be provided in Schedule 14			
32	**5a(ii): Disclosure of Permanent Differences**				
33		In Schedule 14, Box 5, provide descriptions and workings of items recorded in the asterisked categories in Schedule 5a(i).			
34	**5a(iii): Amortisation of Initial Difference in Asset Values**				**($000)**
35					
36		Opening unamortised initial differences in asset values	78,853		
37	*less*	Amortisation of initial differences in asset values	4,956		
38	*plus*	Adjustment for unamortised initial differences in assets acquired	–		
39	*less*	Adjustment for unamortised initial differences in assets disposed	410		
40		Closing unamortised initial differences in asset values			73,487
41					
42		Opening weighted average remaining useful life of relevant assets (years)			16
43					

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SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

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

sch ref				
44	**5a(iv): Amortisation of Revaluations**			**($000)**
45				
46		Opening sum of RAB values without revaluations	487,342	
47				
48		Adjusted depreciation	19,753	
49		Total depreciation	22,502	
50		Amortisation of revaluations		2,749
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**	(27,147)	
61				
62	*plus*	Tax effect of adjusted depreciation	5,531	
63				
64	*less*	Tax effect of tax depreciation	9,100	
65				
66	*plus*	Tax effect of other temporary differences*	1,578	
67				
68	*less*	Tax effect of amortisation of initial differences in asset values	1,388	
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	(248)	
73				
74	*plus*	Deferred tax cost allocation adjustment	(9)	
75				
76		**Closing deferred tax**		(30,287)
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**	331,463	
84	*less*	Tax depreciation	32,499	
85	*plus*	Regulatory tax asset value of assets commissioned	107,374	
86	*less*	Regulatory tax asset value of asset disposals	1,202	
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**		405,136

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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 the ID determination.
This information is part of audited disclosure information (as defined in clause 1.4 of the 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	3,081	
13	Vegetation management	5,454	
14	Routine and corrective maintenance and inspection	9,307	
15	Asset replacement and renewal (opex)	–	
16	**Network opex**		17,842
17	Business support	266	
18	System operations and network support	90	
19	**Operational expenditure**		18,198
20	Consumer connection	5,779	
21	System growth	416	
22	Asset replacement and renewal (capex)	25,286	
23	Asset relocations	672	
24	Quality of supply	–	
25	Legislative and regulatory	–	
26	Other reliability, safety and environment	174	
27	**Expenditure on non-network assets**		170
28	**Expenditure on assets**		32,497
29	Cost of financing		–
30	Value of capital contributions		4,794
31	Value of vested assets		–
32	**Capital Expenditure**		27,703
33	**Total expenditure**		45,901
34			
35	**Other related party transactions**		855

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

37	**Name of related party**	**Nature of opex or capex service provided**	**Total value of transactions ($000)**
38	Delta Utility Services Ltd	Service interruptions and emergencies	3,081
39	Delta Utility Services Ltd	Vegetation management	5,454
40	Delta Utility Services Ltd	Routine and corrective maintenance and inspection	9,307
41	Delta Utility Services Ltd	System operations and network support	90
42	Delta Utility Services Ltd	Business support	225
43	Dunedin Venues Management Ltd	Business support	6
44	Dunedin City Council	Business support	34
45	Dunedin Airport Ltd	Business support	1
46	Delta Utility Services Ltd	Consumer connection	5,779
47	Delta Utility Services Ltd	System growth	416
48	Delta Utility Services Ltd	Asset replacement and renewal (capex)	25,286
49	Delta Utility Services Ltd	Asset relocations	672
50	Delta Utility Services Ltd	Other reliability, safety and environment	174
51	Delta Utility Services Ltd	Expenditure on non-network assets	170
53	**Total value of related party transactions**		50,695

54 ** include additional rows if needed*

55

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**

SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

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

sch ref

7
8 ## 5c(i): Qualifying Debt (may be Commission only)
9

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

17
18 ## 5c(ii): Attribution of Term Credit Spread Differential
19

sch ref			
20	**Gross term credit spread differential**		–
21			
22	Total book value of interest bearing debt		
23	Leverage	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 2022**

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref

		Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
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		3,152			
12	Not directly attributable		–		–	
13	**Total attributable to regulated service**		3,152			
14	**Vegetation management**					
15	Directly attributable		5,462			
16	Not directly attributable		–		–	
17	**Total attributable to regulated service**		5,462			
18	**Routine and corrective maintenance and inspection**					
19	Directly attributable		11,051			
20	Not directly attributable		–		–	
21	**Total attributable to regulated service**		11,051			
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		12,969			
28	Not directly attributable		–		–	
29	**Total attributable to regulated service**		12,969			
30	**Business support**					
31	Directly attributable		13,626			
32	Not directly attributable		–		–	
33	**Total attributable to regulated service**		13,626			
34						
35	**Operating costs directly attributable**		46,260			
36	**Operating costs not directly attributable**	–	–	–	–	–
37	**Operational expenditure**		46,260			
38						

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref		
39	**5d(ii): Other Cost Allocations**	
40	**Pass through and recoverable costs**	**($000)**
41	**Pass through costs**	
42	Directly attributable	3,535
43	Not directly attributable	–
44	**Total attributable to regulated service**	3,535
45	**Recoverable costs**	
46	Directly attributable	27,380
47	Not directly attributable	–
48	**Total attributable to regulated service**	27,380
49		

50	**5d(iii): Changes in Cost Allocations* †**				
51				**($000)**	
52	**Change in cost allocation 1**			**CY-1**	**Current Year (CY)**
53	Cost category		Original allocation		
54	Original allocator or line items		New allocation		
55	New allocator or line items		Difference	–	–
56					
57	Rationale for change				
58					
59					
60				**($000)**	
61	**Change in cost allocation 2**			**CY-1**	**Current Year (CY)**
62	Cost category		Original allocation		
63	Original allocator or line items		New allocation		
64	New allocator or line items		Difference	–	–
65					
66	Rationale for change				
67					
68					
69				**($000)**	
70	**Change in cost allocation 3**			**CY-1**	**Current Year (CY)**
71	Cost category		Original allocation		
72	Original allocator or line items		New allocation		
73	New allocator or line items		Difference	–	–
74					
75	Rationale for change				
76					
77					

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**

SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

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

sch ref

7 5e(i): Regulated Service Asset Values

sch ref		Value allocated ($000s) Electricity distribution services
10	**Subtransmission lines**	
11	Directly attributable	33,418
12	Not directly attributable	–
13	**Total attributable to regulated service**	33,418
14	**Subtransmission cables**	
15	Directly attributable	26,659
16	Not directly attributable	–
17	**Total attributable to regulated service**	26,659
18	**Zone substations**	
19	Directly attributable	109,636
20	Not directly attributable	–
21	**Total attributable to regulated service**	109,636
22	**Distribution and LV lines**	
23	Directly attributable	183,612
24	Not directly attributable	–
25	**Total attributable to regulated service**	183,612
26	**Distribution and LV cables**	
27	Directly attributable	160,034
28	Not directly attributable	–
29	**Total attributable to regulated service**	160,034
30	**Distribution substations and transformers**	
31	Directly attributable	70,277
32	Not directly attributable	–
33	**Total attributable to regulated service**	70,277
34	**Distribution switchgear**	
35	Directly attributable	34,375
36	Not directly attributable	–
37	**Total attributable to regulated service**	34,375
38	**Other network assets**	
39	Directly attributable	18,796
40	Not directly attributable	2,643
41	**Total attributable to regulated service**	21,439
42	**Non-network assets**	
43	Directly attributable	5,851
44	Not directly attributable	–
45	**Total attributable to regulated service**	5,851
46		
47	**Regulated service asset value directly attributable**	642,658
48	**Regulated service asset value not directly attributable**	2,643
49	**Total closing RAB value**	645,301
50		

51 5e(ii): Changes in Asset Allocations* †

sch ref				($000) CY-1	($000) Current Year (CY)
53	**Change in asset value allocation 1**				
54	Asset category		Original allocation		
55	Original allocator or line items		New allocation		
56	New allocator or line items		Difference	–	–
58	Rationale for change				
62	**Change in asset value allocation 2**				
63	Asset category		Original allocation		
64	Original allocator or line items		New allocation		
65	New allocator or line items		Difference	–	–
67	Rationale for change				
71	**Change in asset value allocation 3**				
72	Asset category		Original allocation		
73	Original allocator or line items		New allocation		
74	New allocator or line items		Difference	–	–
76	Rationale for change				

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**

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

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

sch ref

			($000)	($000)
7		**6a(i): Expenditure on Assets**		
8		Consumer connection		17,178
9		System growth		5,032
10		Asset replacement and renewal		55,426
11		Asset relocations		1,256
12		Reliability, safety and environment:		
13		Quality of supply	351	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	2,195	
16		**Total reliability, safety and environment**		2,546
17		**Expenditure on network assets**		81,438
18		Expenditure on non-network assets		3,940
19				
20		**Expenditure on assets**		85,378
21	*plus*	Cost of financing		400
22	*less*	Value of capital contributions		13,946
23	*plus*	Value of vested assets		–
24				
25		**Capital expenditure**		71,832

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

			($000)	($000)
30		**6a(iii): Consumer Connection**		
31		*Consumer types defined by EDB**		
32		All consumers	17,178	
33				
34				
35				
36				
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		17,178
39				
40	*less*	Capital contributions funding consumer connection expenditure	13,054	
41		**Consumer connection less capital contributions**		4,124

			System Growth ($000)	Asset Replacement and Renewal ($000)
42		**6a(iv): System Growth and Asset Replacement and Renewal**		
43				
44				
45		Subtransmission	369	12,502
46		Zone substations	3,365	7,942
47		Distribution and LV lines	1,023	26,648
48		Distribution and LV cables	38	339
49		Distribution substations and transformers	120	579
50		Distribution switchgear	117	6,229
51		Other network assets	–	1,187
52		**System growth and asset replacement and renewal expenditure**	5,032	55,426
53	*less*	Capital contributions funding system growth and asset replacement and renewal	–	–
54		**System growth and asset replacement and renewal less capital contributions**	5,032	55,426
55				

			($000)	($000)
56		**6a(v): Asset Relocations**		
57		*Project or programme**		
58		Timaru River Road, Lake Hayes	188	
59		Mountain View Road, Queenstown	187	
60		Hallenstein Street, Queenstown	168	
61		O'Connells Pavillion redevelopment, Queenstown	132	
62				
63		** include additional rows if needed*		
64		All other projects or programmes - asset relocations	581	
65		**Asset relocations expenditure**		1,256
66	*less*	Capital contributions funding asset relocations	892	
67		**Asset relocations less capital contributions**		364

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**

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

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

sch ref			($000)	($000)
68				
69		**6a(vi): Quality of Supply**		
70		*Project or programme**	($000)	($000)
71		Alexandra 11kV switchboard	246	
72				
73				
74				
75				
76		** include additional rows if needed*		
77		All other projects programmes - quality of supply	105	
78		**Quality of supply expenditure**		351
79	*less*	Capital contributions funding quality of supply		
80		**Quality of supply less capital contributions**		351
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		Omakau transformer - backup power supply	1,551	
96				
97				
98				
99				
100		** include additional rows if needed*		
101		All other projects or programmes - other reliability, safety and environment	644	
102		**Other reliability, safety and environment expenditure**		2,195
103	*less*	Capital contributions funding other reliability, safety and environment		
104		**Other reliability, safety and environment less capital contributions**		2,195
105				
106		**6a(ix): Non-Network Assets**		
107		**Routine expenditure**		
108		*Project or programme**	($000)	($000)
109		Right-of-use assets	629	
110				
111				
112				
113				
114		** include additional rows if needed*		
115		All other projects or programmes - routine expenditure	111	
116		**Routine expenditure**		740
117		**Atypical expenditure**		
118		*Project or programme**	($000)	($000)
119		Development of asset management system	2,098	
120		Development of outage management system	251	
121		New offices	348	
122				
123				
124		** include additional rows if needed*		
125		All other projects or programmes - atypical expenditure	503	
126		**Atypical expenditure**		3,200
127				
128		**Expenditure on non-network assets**		3,940

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**

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

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

sch ref		($000)	($000)
7	**6b(i): Operational Expenditure**		
8	Service interruptions and emergencies	3,152	
9	Vegetation management	5,462	
10	Routine and corrective maintenance and inspection	11,051	
11	Asset replacement and renewal	–	
12	**Network opex**		19,665
13	System operations and network support	12,969	
14	Business support	13,626	
15	**Non-network opex**		26,595
16			
17	**Operational expenditure**		46,260
18	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
19	Energy efficiency and demand side management, reduction of energy losses		–
20	Direct billing*		–
21	Research and development		–
22	Insurance		412
23	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**

SCHEDULE 7: COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE

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

sch ref				
7	**7(i): Revenue**	**Target ($000) [1]**	**Actual ($000)**	**% variance**
8	Line charge revenue	107,100	105,829	(1%)
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	8,632	17,178	99%
11	System growth	4,635	5,032	9%
12	Asset replacement and renewal	59,106	55,426	(6%)
13	Asset relocations	1,967	1,256	(36%)
14	Reliability, safety and environment:			
15	Quality of supply	594	351	(41%)
16	Legislative and regulatory	–	–	–
17	Other reliability, safety and environment	–	2,195	–
18	**Total reliability, safety and environment**	594	2,546	329%
19	**Expenditure on network assets**	74,934	81,438	9%
20	Expenditure on non-network assets	6,086	3,940	(35%)
21	Expenditure on assets	81,020	85,378	5%
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	4,791	3,152	(34%)
24	Vegetation management	5,234	5,462	4%
25	Routine and corrective maintenance and inspection	10,537	11,051	5%
26	Asset replacement and renewal	–	–	–
27	**Network opex**	20,562	19,665	(4%)
28	System operations and network support	16,291	12,969	(20%)
29	Business support	15,222	13,626	(10%)
30	**Non-network opex**	31,513	26,595	(16%)
31	**Operational expenditure**	52,075	46,260	(11%)
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	–	412	–
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 2022**
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**

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	78,090	618,624
16	Load Group 0	General	Standard	322	109
17	Load Group 0A	General	Standard	787	1,803
18	Load Group 1A	General	Standard	918	2,948
19	Load Group 1	General	Standard	5,669	41,669
20	Load Group 2	General	Standard	6,920	259,512
21	Load Group 2	General	Non-standard	0	–
22	Load Group 3	General	Standard	226	56,972
23	Load Group 3	General	Non-standard	0	–
	Load Group 3A	General	Standard	178	82,890
	Load Group 3A	General	Non-standard	0	–
	Load Group 4	General	Standard	143	169,121
	Load Group 4	General	Non-standard	1	3,952
	Load Group 5	General	Standard	8	57,878
	Load Group 5	General	Non-standard	1	5,410
	Street Lighting	General	Standard	13	6,144
	DUML, excl Street Lighting	General	Standard	–	4
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**	93,273	1,297,674
27			**Non-standard consumer totals**	14	9,363
28			**Total for all consumers**	93,287	1,307,036

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)	28,520,310	–	618,624,273	–	–	–	–	–	617,880,611	–	–
Load Group 0 (Standard)	117,641	–	–	103	–	–	–	117,641	–	–	–
Load Group 0A (Standard)	287,645	–	–	340	–	–	–	62,085	–	–	–
Load Group 1A (Standard)	335,393	–	–	2,680,112	–	321,478	–	–	–	2,677,192	321,113
Load Group 1 (Standard)	2,071,131	–	–	31,034,565	–	4,904,278	–	–	–	31,034,565	4,904,278
Load Group 2 (Standard)	2,527,671	–	–	125,689,573	–	17,157,044	(511)	–	–	125,649,058	17,153,688
Load Group 2 (Non-standard)	36	–	–	–	–	–	–	–	–	–	–
Load Group 3 (Standard)	82,562	–	–	15,964,274	259,953,289	3,391,453	(140)	–	–	15,964,274	3,391,453
Load Group 3 (Non-standard)	24	–	–	–	–	–	–	–	–	–	–
Load Group 3A (Standard)	65,010	–	–	19,882,352	280,163,907	4,957,438	(543)	–	–	19,882,352	4,957,438
Load Group 3A (Non-standard)	24	–	–	–	–	–	–	–	–	–	–
Load Group 4 (Standard)	52,110	–	–	37,070,000	556,226,885	9,237,279	91,133	–	–	37,070,000	9,237,279
Load Group 4 (Non-standard)	365	–	–	–	–	–	–	365	–	–	–
Load Group 5 (Standard)	2,921	–	–	8,687,000	108,909,065	2,416,343	8,167	–	–	8,687,000	2,416,343
Load Group 5 (Non-standard)	365	–	–	–	–	–	–	365	–	–	–
Street Lighting (Standard)	730	2,709,444	1,745,034	–	–	–	–	730	1,737,897	–	–
DUML, excl Street Lighting (Standard)	–	–	3,614	–	–	–	–	–	3,614	–	–
Distributed Generation (Large) (Non-standard)	–	–	4,325	–	–	–	–	–	–	–	–
Standard consumer totals	34,063,123	2,709,444	620,372,921	241,008,319	1,205,253,146	42,385,313	98,106	180,456	619,622,122	240,964,441	42,381,592
Non-standard consumer totals	814	–	4,325	–	–	–	–	730	–	–	–
Total for all consumers	34,063,937	2,709,444	620,377,246	241,008,319	1,205,253,146	42,385,313	98,106	181,186	619,622,122	240,964,441	42,381,592

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**
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	$61,938		$53,951	$7,987
38	Load Group 0	General	Standard	$48		$37	$11
39	Load Group 0A	General	Standard	$205		$158	$48
40	Load Group 1A	General	Standard	$383		$370	$12
41	Load Group 1	General	Standard	$3,394		$2,606	$788
42	Load Group 2	General	Standard	$14,479		$12,156	$2,324
43	Load Group 2	General	Non-standard	$5,498		$5,412	$86
44	Load Group 3	General	Standard	$2,348		$1,976	$371
45	Load Group 3	General	Non-standard	$1,293		$1,301	($8)
	Load Group 3A	General	Standard	$3,411		$2,745	$666
	Load Group 3A	General	Non-standard	$1,241		$1,238	$3
	Load Group 4	General	Standard	$5,965		$4,218	$1,747
	Load Group 4	General	Non-standard	$2,659		$2,578	$81
	Load Group 5	General	Standard	$1,345		$762	$583
	Load Group 5	General	Non-standard	$342		$244	$98
	Street Lighting	General	Standard	$544		$496	$48
	DUML, excl Street Lighting	General	Standard	$129		$128	$1
46	Distributed Generation (Large)	General	Non-standard	$608		$608	–
47	*Add extra rows for additional consumer groups or price category codes as necessary*						
48			**Standard consumer totals**	$94,189	–	$79,603	$14,586
49			**Non-standard consumer totals**	$11,640	–	$11,380	$260
50			**Total for all consumers**	$105,829	–	$90,983	$14,846

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	$4,246	–	$49,705	–	–	–	–	–	$7,987	–	–
38	Load Group 0	$37	–	–	–	–	–	–	$11	–	–	–
39	Load Group 0A	$158	–	–	–	–	–	–	$48	–	–	–
40	Load Group 1A	$193	–	–	$106	–	$71	–	($25)	–	($19)	$56
41	Load Group 1	$70	–	–	$1,266	–	$1,270	–	–	–	($198)	$986
42	Load Group 2	$181	–	–	$6,528	–	$5,448	($2)	–	–	($1,678)	$4,002
43	Load Group 2	$73	–	–	$3,217	–	$2,127	($5)	–	–	($732)	$818
44	Load Group 3	$84	–	–	$1,206	$78	$609	–	–	–	($271)	$642
45	Load Group 3	$62	–	–	$529	$246	$466	($2)	–	–	($153)	$145
	Load Group 3A	$76	–	–	$1,570	$114	$987	($3)	–	–	($378)	$1,044
	Load Group 3A	$37	–	–	$500	$229	$475	($3)	–	–	($145)	$148
	Load Group 4	$166	–	–	$1,618	$194	$1,658	$582	–	–	($137)	$1,885
	Load Group 4	$148	–	–	$952	$494	$798	$187	$55	–	($253)	$279
	Load Group 5	$11	–	–	$273	$54	$331	$94	–	–	($61)	$644
	Load Group 5	$91	–	–	$56	$78	$18	–	$116	–	($23)	$6
	Street Lighting	$441	$43	$12	–	–	–	–	$45	$3	–	–
	DUML, excl Street Lighting	$21	$60	$47	–	–	–	–	–	$1	–	–
46	Distributed Generation (Large)	$608	–	–	–	–	–	–	–	–	–	–
48	**Standard consumer totals**	$5,683	$104	$49,764	$12,567	$440	$10,374	$670	$79	$7,991	($2,743)	$9,259
49	**Non-standard consumer totals**	$1,019	–	–	$5,254	$1,046	$3,884	$178	$170	–	($1,305)	$1,395
50	**Total for all consumers**	$6,702	$104	$49,764	$17,820	$1,487	$14,258	$848	$249	$7,991	($4,048)	$10,655

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** 8

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**
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	49,235	401,289
16	Load Group 0	General	Standard	103	47
17	Load Group 0A	General	Standard	170	371
18	Load Group 1A	General	Standard	412	1,345
19	Load Group 1	General	Standard	2,850	20,789
20	Load Group 2	General	Standard	3,128	126,362
21	Load Group 2	General	Non-standard	–	–
22	Load Group 3	General	Standard	104	29,866
23	Load Group 3	General	Non-standard	–	–
	Load Group 3A	General	Standard	91	49,421
	Load Group 3A	General	Non-standard	–	–
	Load Group 4	General	Standard	74	99,787
	Load Group 4	General	Non-standard	–	–
	Load Group 5	General	Standard	6	46,567
	Load Group 5	General	Non-standard	–	–
	Street Lighting	General	Standard	2	4,399
	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**	56,174	780,245
27			**Non-standard consumer totals**	1	–
28			**Total for all consumers**	56,175	780,245

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	17,970,604		401,288,932						401,288,932		
Load Group 0	37,671			103				37,671			
Load Group 0A	62,085			340				62,085			
Load Group 1A	150,297			1,201,936		139,547				1,201,936	139,547
Load Group 1	1,040,152			15,596,370		2,398,515				15,596,370	2,398,515
Load Group 2	1,141,765			58,269,044		8,378,642				58,269,044	8,378,642
Load Group 2 (Non-standard)	–									–	–
Load Group 3	37,847			7,407,070	41,770,924	1,907,318				7,407,070	1,907,318
Load Group 3 (Non-standard)	–									–	–
Load Group 3A	33,090			10,093,930	54,326,316	3,170,878	(263)			10,093,930	3,170,878
Load Group 3A (Non-standard)	–									–	–
Load Group 4	27,135			19,298,000	108,242,101	5,387,544	48,217			19,298,000	5,387,544
Load Group 4 (Non-standard)	–										
Load Group 5	2,190			6,862,000	47,680,315	2,186,937	8,167			6,862,000	2,186,937
Load Group 5 (Non-standard)	–										
Street Lighting	730							730			
DUML, excl Street Lighting	–		3,614						3,614		
Distributed Generation (Large)	–		–						–		
Standard consumer totals	20,503,566	–	401,292,546	118,728,793	252,019,656	23,569,381	56,121	100,486	401,292,546	118,728,350	23,569,381
Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–	–
Total for all consumers	20,503,566	–	401,292,546	118,728,793	252,019,656	23,569,381	56,121	100,486	401,292,546	118,728,350	23,569,381

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**
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.

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	$34,889		$28,105	$6,784
38	Load Group 0	General	Standard	$21		$19	$3
39	Load Group 0A	General	Standard	$76		$64	$12
40	Load Group 1A	General	Standard	$163		$136	$27
41	Load Group 1	General	Standard	$2,402		$1,836	$567
42	Load Group 2	General	Standard	$8,602		$7,296	$1,306
43	Load Group 2	General	Non-standard	–		–	–
44	Load Group 3	General	Standard	$1,752		$1,457	$295
45	Load Group 3	General	Non-standard	–		–	–
	Load Group 3A	General	Standard	$2,538		$1,977	$561
	Load Group 3A	General	Non-standard	–		–	–
	Load Group 4	General	Standard	$4,298		$2,927	$1,371
	Load Group 4	General	Non-standard	–		–	–
	Load Group 5	General	Standard	$1,256		$704	$552
	Load Group 5	General	Non-standard	–		–	–
	Street Lighting	General	Standard	$486		$441	$45
	DUML, excl Street Lighting	General	Standard	$0		$0	$0
46	Distributed Generation (Large)	General	Non-standard	$133		$133	–
47	*Add extra rows for additional consumer groups or price category codes as necessary*						
48			**Standard consumer totals**	$56,485	–	$44,963	$11,522
49			**Non-standard consumer totals**	$133	–	$133	–
50			**Total for all consumers**	$56,617	–	$45,095	$11,522

Line charge revenues ($000) by price component

Row	Price component / Rate (eg, $ per day, $ per kWh, etc.)	Fixed (Distribution) $ / annum	Fixed (Distribution) $ / Lamp	Energy Delivery (Distribution) $ / kWh	Capacity (Distribution) $ / kVA	Capacity - Distance (Distribution) $ / kVA x km	Control Period Demand (Distribution) $ / kW	Transformer Lease, Other Charges & Rebates (Distribution) $ / kVA	Fixed (Transmission) $ / annum	Energy Delivery (Transmission) $ / kWh	Capacity (Transmission) $ / kVA	Control Period Demand (Transmission) $ / kW
37	Residential	$2,674		$25,431						$6,784		
38	Load Group 0	$19							$3			
39	Load Group 0A	$64							$12			
40	Load Group 1A	$7			$76		$53				($12)	$39
41	Load Group 1	$48			$883		$905				($109)	$676
42	Load Group 2 (Standard)	$109			$4,026		$3,161	–			($1,054)	$2,360
43	Load Group 2 (Non-standard)	–										
44	Load Group 3 (Standard)	$65			$860	$46	$486				($239)	$533
45	Load Group 3 (Non-standard)	–										
	Load Group 3A (Standard)	$57			$1,055	$60	$809	($3)			($325)	$886
	Load Group 3A (Non-standard)	–										
	Load Group 4 (Standard)	$122			$1,100	$119	$1,178	$409			($135)	$1,506
	Load Group 4 (Non-standard)	–										
	Load Group 5 (Standard)	$10			$262	$52	$307	$73			($60)	$611
	Load Group 5 (Non-standard)	–							–			
	Street Lighting	$441							$45			
	DUML, excl Street Lighting	$0		$0						$0		
46	Distributed Generation (Large)	$133										
48	Standard consumer totals	$3,615	–	$25,431	$8,263	$277	$6,898	$478	$60	$6,784	($1,934)	$6,612
49	Non-standard consumer totals	$133	–	–	–	–	–	–	–	–	–	–
50	Total for all consumers	$3,748	–	$25,431	$8,263	$277	$6,898	$478	$60	$6,784	($1,934)	$6,612

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** 1

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**
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(i): Billed Quantities by Price Component

Billed quantities by price component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)	Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control 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	Residential	Standard	17,629	121,108	6,452,175		121,108,209						121,108,209		
Load Group 0	General	Standard	108	20	39,482							39,482			
Load Group 0A	General	Standard	391	844	143,174										
Load Group 1A	General	Standard	324	1,046	118,503			945,432		113,299				945,432	113,299
Load Group 1	General	Standard	1,766	12,650	646,498			9,670,980		1,374,288				9,670,980	1,374,288
Load Group 2	General	Standard	2,015	73,153	737,323			37,524,918		4,061,350	(385)			37,524,918	4,061,350
Load Group 2	General	Non-Standard	0	–	36			–		–				–	–
Load Group 3	General	Standard	90	17,698	32,906			6,103,343	189,015,193	837,403	(140)			6,103,343	837,403
Load Group 3	General	Non-Standard	0	–	24			–	–	–	–			–	–
Load Group 3A	General	Standard	54	21,433	19,607			5,805,122	176,102,521	854,540	(280)			5,805,122	854,540
Load Group 3A	General	Non-Standard	0	–	24			–	–	–	–			–	–
Load Group 4	General	Standard	39	33,569	14,251			10,266,000	379,622,042	1,608,346	22,375			10,266,000	1,608,346
Load Group 4	General	Non-Standard	–	–	–					–		–			
Load Group 5	General	Standard	1	8,157	366			912,500	60,133,750	35,956				912,500	35,956
Load Group 5	General	Non-Standard	–	–	–			–	–	–		–			
Street Lighting	General	Standard	7	919		1,604,846	918,966						918,966		
DUML, excl Street Lighting	General	Standard	–	–											
Distributed Generation (Large)	General	Non-standard	–	–	–		3,196								
Add extra rows for additional consumer groups or price category codes as necessary															
		Standard consumer totals	22,423	290,599	8,204,284	1,604,846	122,027,175	71,228,295	804,873,506	8,885,182	21,570	39,482	122,027,175	71,228,295	8,885,182
		Non-standard consumer totals	0	–	84	–	3,196	–	–	–	–	–	–	–	–
		Total for all consumers	22,423	290,599	8,204,368	1,604,846	122,030,371	71,228,295	804,873,506	8,885,182	21,570	39,482	122,027,175	71,228,295	8,885,182

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**
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	$16,909		$17,486	($577)
38	Umetered Load	Non-domestic	Standard	–		–	–
39	Load Group 0	General	Standard	$23		$27	($3)
40	Load Group 0A	General	Standard	$159		$184	($25)
41	Load Group 1A	General	Standard	$173		$156	$17
42	Load Group 1	General	Standard	$1,676		$1,503	$173
43	Load Group 2	General	Standard	$5,498		$5,412	$86
44	Load Group 2	General	Non-Standard	–		–	–
45	Load Group 3	General	Standard	$1,293		$1,301	($8)
	Load Group 3	General	Non-Standard	–		–	–
	Load Group 3A	General	Standard	$1,241		$1,238	$3
	Load Group 3A	General	Non-Standard	–		–	–
	Load Group 4	General	Standard	$2,527		$2,501	$26
	Load Group 4	General	Non-Standard	–		–	–
	Load Group 5	General	Standard	$137		$154	($17)
	Load Group 5	General	Non-Standard	–		–	–
	Street Lighting	General	Standard	$108		$108	$1
46	Distributed Generation (Large)	General	Non-standard	$475		$475	–
47	*Add extra rows for additional consumer groups or price category codes as necessary*						
48			**Standard consumer totals**	$29,745	–	$30,069	($324)
49			**Non-standard consumer totals**	$475	–	$475	–
50			**Total for all consumers**	$30,220	–	$30,544	($324)

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 (Standard)	$962		$16,524						($577)		
38	Umetered Load (Standard)	–								–		
39	Load Group 0 (Standard)	$27							($3)			
40	Load Group 0A (Standard)	$184							($25)			
41	Load Group 1A (Standard)	$6			$82		$68				($14)	$31
42	Load Group 1 (Standard)	$31			$647		$826	($0)			($203)	$376
43	Load Group 2 (Standard)	$73			$3,217		$2,127	($5)			($732)	$818
44	Load Group 2 (Non-Standard)	–			–		–	–			–	–
45	Load Group 3 (Standard)	$62			$529	$246	$466	($2)			($153)	$145
	Load Group 3 (Non-Standard)	–			–	–		–			–	
	Load Group 3A (Standard)	$37			$500	$229	$475	($3)			($145)	$148
	Load Group 3A (Non-Standard)	–			–	–		–			–	
	Load Group 4 (Standard)	$71			$952	$494	$798	$187			($253)	$279
	Load Group 4 (Non-Standard)	–							–			
	Load Group 5 (Standard)	$2			$56	$78	$18				($23)	$6
	Load Group 5 (Non-Standard)	–							–			
	Street Lighting (Standard)	–	$60	$47						$1		
46	Distributed Generation (Large) (Non-standard)	$475										
48	**Standard consumer totals**	$1,453	$60	$16,571	$5,983	$1,046	$4,777	$177	($28)	($576)	($1,522)	$1,802
49	**Non-standard consumer totals**	$475	–	–	–	–	–	–	–	–	–	–
50	**Total for all consumers**	$1,929	$60	$16,571	$5,983	$1,046	$4,777	$177	($28)	($576)	($1,522)	$1,802

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

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

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**
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	11,094	95,483
16	Load Group 0	General	Standard	111	42
17	Load Group 0A	General	Standard	223	584
18	Load Group 1A	General	Standard	181	553
19	Load Group 1	General	Standard	1,053	8,230
20	Load Group 2	General	Standard	1,773	59,954
21	Load Group 2	General	Non-Standard	–	–
22	Load Group 3	General	Standard	32	9,408
23	Load Group 3	General	Non-Standard	–	–
	Load Group 3A	General	Standard	34	12,036
	Load Group 3A	General	Non-Standard	–	–
	Load Group 4	General	Standard	29	35,765
	Load Group 4	General	Non-Standard	1	3,952
	Load Group 5	General	Standard	1	3,154
	Load Group 5	General	Non-Standard	1	5,410
	Street Lighting	General	Standard	3	819
	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**	14,536	226,029
27			**Non-standard consumer totals**	4	9,363
28			**Total for all consumers**	14,540	235,392

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)	4,049,389		95,483,470						95,483,470		
Load Group 0 (Standard)	40,488							40,488			
Load Group 0A (Standard)	81,523										
Load Group 1A (Standard)	66,228			529,824		68,267				529,824	68,267
Load Group 1 (Standard)	384,481			5,767,215		1,131,475				5,767,215	1,131,475
Load Group 2 (Standard)	647,123			29,855,096		4,713,696	(126)			29,855,096	4,713,696
Load Group 2 (Non-Standard)	–			–		–				–	–
Load Group 3 (Standard)	11,809			2,453,861	29,167,172	646,732	–			2,453,861	646,732
Load Group 3 (Non-Standard)	–			–	–	–	–			–	–
Load Group 3A (Standard)	12,313			3,983,300	49,735,070	932,020	–			3,983,300	932,020
Load Group 3A (Non-Standard)	–			–	–	–	–			–	–
Load Group 4 (Standard)	10,724			7,506,000	68,362,742	2,241,389	20,542			7,506,000	2,241,389
Load Group 4 (Non-Standard)	365					–		365			
Load Group 5 (Standard)	365			912,500	1,095,000	193,450				912,500	193,450
Load Group 5 (Non-Standard)	365			–	–	–		365			
Street Lighting (Standard)		1,075,033	818,931						818,931		
DUML, excl Street Lighting (Standard)											
Distributed Generation (Large) (Non-standard)	–		1,129								
Standard consumer totals	5,304,443	1,075,033	96,302,401	51,007,796	148,359,984	9,927,029	20,416	40,488	96,302,401	51,007,796	9,927,029
Non-standard consumer totals	730	–	1,129	–	–	–	–	730	–	–	–
Total for all consumers	5,305,173	1,075,033	96,303,530	51,007,796	148,359,984	9,927,029	20,416	41,218	96,302,401	51,007,796	9,927,029

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**
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**

32

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	$10,042		$8,262	$1,780
38	Load Group 0	General	Standard	$26		$18	$8
39	Load Group 0A	General	Standard	$105		$66	$39
40	Load Group 1A	General	Standard	$60		$50	$10
41	Load Group 1	General	Standard	$818		$614	$204
42	Load Group 2	General	Standard	$4,197		$3,351	$845
43	Load Group 2	General	Non-Standard	–		–	–
44	Load Group 3	General	Standard	$596		$519	$77
45	Load Group 3	General	Non-Standard	–		–	–
	Load Group 3A	General	Standard	$873		$768	$105
	Load Group 3A	General	Non-Standard	–		–	–
	Load Group 4	General	Standard	$1,667		$1,291	$377
	Load Group 4	General	Non-Standard	$131		$77	$55
	Load Group 5	General	Standard	$89		$58	$32
	Load Group 5	General	Non-Standard	$205		$90	$116
	Street Lighting	General	Standard	$56		$54	$3
	DUML, excl Street Lighting	General	Standard	$21		$21	–
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**	$18,550	–	$15,071	$3,479
49			**Non-standard consumer totals**	$336	–	$166	$170
50			**Total for all consumers**	$18,886	–	$15,238	$3,649

33 **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	$603		$7,659						$1,780		
38	Load Group 0	$18	–	–	–	–	–	–	$8	–	–	–
39	Load Group 0A	$66	–	–	–	–	–	–	$39	–	–	–
40	Load Group 1A	$3	–	–	$29	–	$18	–	–	–	($7)	$17
41	Load Group 1	$16	–	–	$300	–	$298	–	–	–	($75)	$279
42	Load Group 2	$42	–	–	$1,852	–	$1,459	($2)	–	–	($421)	$1,266
43	Load Group 2	–	–	–	–	–	–	–	–	–	–	–
44	Load Group 3	$19	–	–	$346	$32	$123	–	–	–	($33)	$109
45	Load Group 3	–	–	–	–	–	–	–	–	–	–	–
	Load Group 3A	$19	–	–	$515	$55	$179	–	–	–	($53)	$158
	Load Group 3A	–	–	–	–	–	–	–	–	–	–	–
	Load Group 4	$44	–	–	$518	$75	$480	$173	–	–	($2)	$379
	Load Group 4	$77	–	–	–	–	–	–	$55	–	–	–
	Load Group 5	$1	–	–	$11	$1	$24	$21	–	–	($1)	$33
	Load Group 5	$90	–	–	–	–	–	–	$116	–	–	–
	Street Lighting	–	$42	$11	–	–	–	–	–	$3	–	–
	DUML, excl Street Lighting	$21	–	–	–	–	–	–	–	–	–	–
46	Distributed Generation (Large)	–	–	–	–	–	–	–	–	–	–	–
48	**Standard consumer totals**	$851	$42	$7,670	$3,572	$163	$2,580	$192	$47	$1,783	($592)	$2,241
49	**Non-standard consumer totals**	$166	–	–	–	–	–	–	$170	–	–	–
50	**Total for all consumers**	$1,018	$42	$7,670	$3,572	$163	$2,580	$192	$217	$1,783	($592)	$2,241

34 **Price component**

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

51

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

Check OK

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**
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.	28,150	29,480	1,330	4
10	All	Overhead Line	Wood poles	No.	25,757	24,194	(1,563)	4
11	All	Overhead Line	Other pole types	No.			–	3
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	524	523	(1)	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km			–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	34	35	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	35	–	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.	144	145	1	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.	49	52	3	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	334	332	(2)	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	22	22	–	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	67	67	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2,289	2,279	(10)	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	715	748	34	3
39	HV	Distribution Cable	Distribution UG PILC	km	421	418	(3)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	1	5	3	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	54	56	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.	6,678	7,164	486	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	553	509	(44)	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	834	888	54	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	3,987	3,984	(3)	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	3,206	3,259	53	4
48	HV	Distribution Transformer	Voltage regulators	No.	28	28	–	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	354	350	(4)	4
50	LV	LV Line	LV OH Conductor	km	1,040	1,032	(8)	4
51	LV	LV Cable	LV UG Cable	km	1,076	1,112	36	4
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	1,064	1,069	5	4
53	LV	Connections	OH/UG consumer service connections	No.	94,261	95,348	1,087	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	803	779	(24)	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	21	–	4
58	All	Load Control	Relays	No	2,286	2,292	6	2
59	All	Civils	Cable Tunnels	km			–	N/A

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**
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	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.	17,815	18,168	353	4
10	All	Overhead Line	Wood poles	No.	11,568	11,033	(535)	4
11	All	Overhead Line	Other pole types	No.			–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	144	144	0	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.	75	76	1	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.	18	19	1	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	246	244	(2)	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	726	722	(4)	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	47	52	5	3
39	HV	Distribution Cable	Distribution UG PILC	km	276	275	(1)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	1	5	3	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.	2,631	2,849	218	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	338	299	(39)	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	383	398	15	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	1,673	1,675	2	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	987	987	–	4
48	HV	Distribution Transformer	Voltage regulators	No.	2	2	–	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	354	350	(4)	4
50	LV	LV Line	LV OH Conductor	km	817	811	(6)	4
51	LV	LV Cable	LV UG Cable	km	297	305	8	4
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	682	683	1	4
53	LV	Connections	OH/UG consumer service connections	No.	56,846	57,147	301	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	603	581	(22)	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	18	–	4
58	All	Load Control	Relays	No	1,128	1,125	(3)	2
59	All	Civils	Cable Tunnels	km			–	N/A

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**
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								
9	All	Overhead Line	Concrete poles / steel structure	No.	8,803	9,593	790	4
10	All	Overhead Line	Wood poles	No.	11,007	10,200	(807)	4
11	All	Overhead Line	Other pole types	No.			–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	301	310	8	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km			–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	8	9	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	0	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	9	–	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	50	–	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.	20	21	1	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	48	48	–	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	12	11	(1)	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	19	19	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1,275	1,271	(3)	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	472	493	21	3
39	HV	Distribution Cable	Distribution UG PILC	km	61	60	(0)	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.	25	27	2	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.	3,141	3,333	192	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	91	88	(3)	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	223	247	24	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	1,855	1,853	(2)	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	1,395	1,433	38	4
48	HV	Distribution Transformer	Voltage regulators	No.	18	18	–	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.			–	N/A
50	LV	LV Line	LV OH Conductor	km	177	176	(1)	4
51	LV	LV Cable	LV UG Cable	km	470	490	20	4
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	241	244	3	4
53	LV	Connections	OH/UG consumer service connections	No.	22,502	23,042	540	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	111	120	9	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	–	–	–	N/A
57	All	Load Control	Centralised plant	Lot	2	2	–	4
58	All	Load Control	Relays	No	687	693	6	2
59	All	Civils	Cable Tunnels	km			–	N/A

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**
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.	1,532	1,719	187	4
10	All	Overhead Line	Wood poles	No.	3,182	2,961	(221)	4
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	79	70	(9)	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	12	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.	11	12	1	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	288	285	(3)	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	196	203	7	3
39	HV	Distribution Cable	Distribution UG PILC	km	83	82	(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.	906	982	76	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	123	121	(2)	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	227	242	15	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	459	456	(3)	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	819	834	15	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	46	(1)	4
51	LV	LV Cable	LV UG Cable	km	303	311	8	4
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	140	140	1	4
53	LV	Connections	OH/UG consumer service connections	No.	14,773	15,016	243	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	1	–	(1)	4
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	466	469	3	2
59	All	Civils	Cable Tunnels	km			–	N/A

Company Name	Aurora Energy Limited
For Year Ended	31 March 2022
Network / Sub-network Name	Total Network

SCHEDULE 9b: ASSET AGE PROFILE

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

sch ref

8 Disclosure Year (year ended) 31 March 2022

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	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.		18	1,514	6,101	4,419	2,984	1,662	100	73	121	152	137	65	108	169	174	160	113	132	347	541	443	727	633	962	2,249	1,487	1,062	1,266	1,561					29,480		4
11	All	Overhead Line	Wood poles	No.	652	714	1,392	5,730	4,143	3,183	2,836	296	224	225	405	293	304	235	293	293	271	350	345	242	140	89	102	95	135	633	191	129	126	128					24,194		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	125	0					0		6		1	6	11		0	0	3	2		1	1	0		11					523		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					35		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								35		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.			39	18	4	23	17	1				1		2			15		2			18		1			2		2						145		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	4					52		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						332		4
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.					3		2				4	2		4					1	1					1		1		1	2					22		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					67		4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	57	98	255	408	395	363	339	12	12	14	7	11	30	8	12	7	9	13	13	6	8	6	16	23	10	13	11	27	29	70					2,279		4
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km																																			–		N/A
38	HV	Distribution Line	SWER conductor	km			6	2	0	1	0																0												9		4
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km				0	6	10	63	12	24	25	29	53	32	39	51	34	21	15	14	10	10	29	40	40	27	29	34	29	38	35					748		3
40	HV	Distribution Cable	Distribution UG PILC	km	0	8	34	48	69	74	66	6	6	9	13	6	9	11	15	5	8	9	7	5	3	4	1	1	0	0	0		0	0					418		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 sectionalisers	No.							2	1				2	3	1	4	7	7	1	1		2			8	1	3		1	8	4					56		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	19	102	542	529	663	1,101	138	123	136	153	176	136	149	135	142	145	151	156	106	124	121	173	157	133	235	293	304	367	453					7,164		4
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.				68	51	60	68	7	3	19	21	16	25	18	32	19	27	23	11	13	15	3	2	1	1	2	2	2							509		3
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.				1	36	59	122	12	18	17	40	10	25	24	18	22	24	17	21	24	13	18	18	34	39	31	56	60	65	64					888		3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.		4	29	218	380	505	911	109	89	102	108	101	78	73	68	72	74	56	53	58	81	62	82	62	40	85	89	111	143	141					3,984		4
48	HV	Distribution Transformer	Ground Mounted Transformer	No.			1	38	162	180	445	60	97	98	118	151	172	168	143	119	127	55	84	61	65	86	102	105	99	97	112	104	111	99					3,259		4
49	HV	Distribution Transformer	Voltage regulators	No.					1									3	3		4	5			3		4						3	2					28		4
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.				2	107	95	123	8	2	4	1		2	1		1			1			1	1					1							350		4
51	LV	LV Line	LV OH Conductor	km	51	41	105	233	215	160	173	5	4	3	4	5	3	3	3	2	2	3	2	1	2	2	2	1	1	1	1	2	2	1					1,032		4
52	LV	LV Cable	LV UG Cable	km	0	0	1	22	43	160	157	19	21	25	41	48	51	49	46	40	36	22	14	20	15	20	23	28	31	33	41	41	30	32					1,112		4
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	13	11	32	140	152	242	288	7	7	8	9	10	10	9	10	11	9	9	7	10	7	7	4	12	8	11	9	8	4	4					1,069		4
54	LV	Connections	OH/UG consumer service connections	No.	12,329	3,515	6,839	8,647	7,080	4,488	21,819	1,012	956	1,208	1,378	1,568	1,569	1,748	1,533	1,664	1,231	1,102	1,017	888	1,026	1,111	1,216	1,252	1,661	1,505	1,533	1,417	1,571	1,352				113	95,348		4
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	30		147	93	120	30	48			9	38	3	15		10		13	36	14	2	1	30	11	8		49	1	13	58						779		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			3	6	5		1										1	1	3				1												21		4
59	All	Load Control	Relays	No		1	2	39	80	105	253	24	45	43	58	102	133	121	112	85	62	30	27	28	16	22	9	519	239	27	26	38	29	17					2,292		2
60	All	Civils	Cable Tunnels	km																																			–		N/A

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**
Network / Sub-network Name	**Dunedin Sub-network**

SCHEDULE 9b: ASSET AGE PROFILE

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

sch ref

8 **Disclosure Year (year ended)** 31 March 2022

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
10	All	Overhead Line	Concrete poles / steel structure	No.		3	1,430	5,734	2,766	2,002	758	23	12	41	52	23	17	24	29	19	18
11	All	Overhead Line	Wood poles	No.	652	692	1,297	2,369	965	1,155	1,510	171	154	119	113	87	114	102	110	144	129
12	All	Overhead Line	Other pole types	No.																	
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	49		51	28	3		2										
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km																	
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km																0	
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km					22	3											
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km				16													
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km			8		0	0	1	0		0	0	0	1		0	0	
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km																	
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km																	
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km																	
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km																	
23	HV	Subtransmission Cable	Subtransmission submarine cable	km																	
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.		1	4	3	6	4	1										
25	HV	Zone substation Buildings	Zone substations 110kV+	No.																	
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.																	
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.																	
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.																	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.			25	18	4		5										
30	HV	Zone substation switchgear	33kV RMU	No.																	
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.																	
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.					4						1				3	4	
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.			46	36	62	17	13					17		9			
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.																	
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.			3	9	10	2	2									1	
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1	22	83	243	127	70	66	5	4	8	3	4	5	5	2	5	5
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km																	
38	HV	Distribution Line	SWER conductor	km			6	2	0	1	0										
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km				0	0	0	4	1	1	2	2	2	2	3	3	1	1
40	HV	Distribution Cable	Distribution UG PILC	km	0	8	34	48	69	48	30	2	1	1	1	1	2	3	1	1	3
41	HV	Distribution Cable	Distribution Submarine Cable	km		1															
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.															3		3
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.			3		2												
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1	16	71	454	370	347	439	15	15	19	28	37	32	54	34	25	24
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.				68	51	60	51	5		9	4	5		3	2	4	9
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.				1	36	56	83	10	7	3	8	5	11	5	3	3	9
47	HV	Distribution Transformer	Pole Mounted Transformer	No.			4	149	207	249	437	42	28	27	39	28	30	34	25	20	16
48	HV	Distribution Transformer	Ground Mounted Transformer	No.			1	38	146	130	211	16	10	16	21	15	20	36	18	12	21
49	HV	Distribution Transformer	Voltage regulators	No.					1												
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.				2	107	95	123	8	2	4	1		2	1		1	
51	LV	LV Line	LV OH Conductor	km	48	25	66	170	170	141	149	4	3	2	3	4	3	2	2	1	1
52	LV	LV Cable	LV UG Cable	km	0	0	1	22	42	34	39	4	3	4	5	8	9	13	11	7	8
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
54	LV	Connections	OH/UG consumer service connections	No.	12,329	3,515	6,839	8,643	7,072	4,483	4,844	311	283	249	361	487	433	528	506	538	363
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	27		147	92	114	3	19				19	3	12				2
56	All	SCADA and communications	SCADA and communications equipment operating as a single sys	Lot																	
57	All	Capacitor Banks	Capacitors including controls	No																	
58	All	Load Control	Centralised plant	Lot			3	6	5		1										
59	All	Load Control	Relays	No		1	2	35	62	56	93	6	2	4	4	4	2	3	5	6	7
60	All	Civils	Cable Tunnels	km																	

9	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	No. with default dates	Data accuracy (1–4)
10	25	27	79	155	168	310	292	524	1,046	881	604	550	556					18,168		4
11	89	82	100	61	35	20	19	37	487	103	58	40	19					11,033		4
12																		–		N/A
13													11					144		4
14																		–		N/A
15		0	0		3		0	0	3	6			0					14		3
16																		25		3
17																		16		3
18			0															11		3
19																		–		N/A
20																		–		N/A
21																		–		N/A
22																		–		N/A
23																		–		N/A
24									1	1								21		4
25																		–		N/A
26																		–		N/A
27																		–		4
28																		–		N/A
29		2			18					2		2						76		4
30																		–		4
31										3								3		4
32			3	2									2					19		4
33	11	17								16								244		4
34													1					1		4
35		2		2						2			1					34		4
36	5	1	1	0	2	2	0	0	0	0	14	9	28					722		4
37																		–		N/A
38						0												9		4
39	0	2	1	1	1	1	2	4	2	2	4	3	5					52		3
40	3	6	3	3	3	1	1	0	0	0		0	0					275		3
41													3					5		4
42		1					4		1		1	1	1					15		4
43		1																6		4
44	20	21	18	25	34	37	44	43	60	74	140	137	215					2,849		4
45	1	6	5	10	2				1	1	2							299		3
46	7	10	8	9	9	8	8	15	4	12	15	25	28					398		3
47	16	13	19	21	16	29	14	19	26	23	39	42	63					1,675		4
48	14	21	20	16	20	19	23	27	27	15	33	29	12					987		4
49												1						2		4
50		1			1	1					1							350		4
51	2	2	0	2	1	1	1	1	0	1	1	1	1					811		4
52	8	4	8	7	8	7	6	8	8	7	8	8	8					305		4
53	6	4	6	4	3	2	5	4	2	1	1	1	1					683		4
54	433	376	379	365	378	414	364	444	426	454	427	468	432				3	57,147		4
55	28	1			20	4	2		28	1	13	46						581		4
56										1								1		4
57			3															3		4
58		3																18		4
59	5	5	14	4	4	4	509	230	13	5	14	20	6					1,125		2
60																		–		N/A

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**
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)** 31 March 2022

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
10	All	Overhead Line	Concrete poles / steel structure	No.		15	84	333	1,434	743	706	64	47	70	82	99	38	71	124
11	All	Overhead Line	Wood poles	No.		17	94	2,860	2,438	1,398	890	90	47	85	266	163	155	103	153
12	All	Overhead Line	Other pole types	No.															
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	9		9	67	59	34	104	0							4
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km															
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km						1	1					0	0	1	0
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km															
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km															
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km							0								
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km															
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km															
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km															
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km															
23	HV	Subtransmission Cable	Subtransmission submarine cable	km															
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.					1	2	1								
25	HV	Zone substation Buildings	Zone substations 110kV+	No.															
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.															
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.												3			
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.															
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.			14			19	12	1				1		2	
30	HV	Zone substation switchgear	33kV RMU	No.															
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.															
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.						7	4			1			1		
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.						7					11			1	
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.					1		1				4	2			
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.			1	1	1	2	1			1	3	1			
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	45	74	163	120	253	201	190	5	6	5	2	7	24	1	6
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km															
38	HV	Distribution Line	SWER conductor	km															
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km				0	5	8	32	7	14	14	20	33	17	22	35
40	HV	Distribution Cable	Distribution UG PILC	km	0				0	13	15	2	3	4	3	4	5	2	6
41	HV	Distribution Cable	Distribution Submarine Cable	km															
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionaliser:	No.							2	1				2	1		1
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.															
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1	3	29	79	139	247	446	82	66	74	94	101	73	69	72
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.							7	1		8	5	2	11	1	14
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.						1	15	1	4	8	11	1	9	4	6
47	HV	Distribution Transformer	Pole Mounted Transformer	No.		4	23	60	147	208	342	46	44	55	56	57	37	34	36
48	HV	Distribution Transformer	Ground Mounted Transformer	No.					9	33	121	18	49	46	56	76	92	72	82
49	HV	Distribution Transformer	Voltage regulators	No.															
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.															
51	LV	LV Line	LV OH Conductor	km	3	14	30	51	31	17	17	1	1	0	1	1	1	1	1
52	LV	LV Cable	LV UG Cable	km					1	71	64	5	8	13	18	22	29	21	17
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
54	LV	Connections	OH/UG consumer service connections	No.				3	5	4	10,714	342	322	490	571	607	589	590	582
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	2			1	6	16	3			4	19				10
56	All	SCADA and communications	SCADA and communications equipment operating as a single sys	Lot															
57	All	Capacitor Banks	Capacitors including controls	No															
58	All	Load Control	Centralised plant	Lot															
59	All	Load Control	Relays	No				4	12	31	89	7	22	23	29	57	78	66	68
60	All	Civils	Cable Tunnels	km															

sch ref	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	No. with default dates	Data accuracy (1–4)
10	126	129	84	75	216	376	250	374	320	390	1,006	508	407	641	781					9,593		4
11	102	99	215	221	106	50	51	71	69	81	118	59	54	65	80					10,200		4
12																				–		N/A
13			6	11			0	2	2		1	1	0		0					310		4
14																				–		N/A
15			1				0		1			3		0	0					9		3
16																				–		N/A
17																				–		N/A
18																				0		3
19																				–		N/A
20																				–		N/A
21																				–		N/A
22																				–		N/A
23																				–		N/A
24				1			1	1	1	1										9		4
25																				–		N/A
26																				–		N/A
27				1				2	1			7								14		4
28																				–		N/A
29									1											50		4
30														1						1		4
31																				–		N/A
32		1					3			1				2	1					21		4
33	8			3		2	3	6	5					2						48		4
34										1				1	1					11		4
35				1			1	1	2					3						19		4
36	1	3	6	11	2	7	5	12	22	4	11	10	13	19	42					1,271		4
37																				–		N/A
38																				–		N/A
39	17	15	10	8	7	9	28	34	32	16	22	22	18	27	22					493		3
40	1	0	2	1	1	0	0													60		3
41																				–		N/A
42	7	2	1			1			3	1	2			1	2					27		4
43																				–		N/A
44	95	86	97	109	63	84	84	122	96	75	148	183	134	188	194					3,333		4
45	2	11	10	2	7	3		1	1	1		1								88		3
46	6	3	6	7	8	3	6	5	12	8	17	26	30	26	24					247		3
47	43	40	25	34	35	49	43	45	40	18	50	57	63	96	66					1,853		4
48	60	69	28	30	28	38	56	76	58	51	57	63	52	56	57					1,433		4
49		2	5			3		4						2	2					18		4
50																				–		N/A
51	0	1	1	0	0	0	0	0	0	0	0	0	1	1	0					176		4
52	22	15	11	6	8	5	9	11	16	17	18	27	22	15	19					490		4
53	7	5	2	2	3	3	3	2	3	3	4	4	6	2	2					244		4
54	699	543	367	343	279	347	417	506	611	758	699	673	650	652	611				68	23,042		4
55			8			1	5	7	6		20			12						120		4
56																				–		N/A
57																				–		N/A
58		1						1												2		4
59	42	38	16	10	8	9	13	5	6	7	7	14	21	3	8					693		2
60																				–		N/A

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**
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)** 31 March 2022

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
10	All	Overhead Line	Concrete poles / steel structure	No.				34	219	239	198	13	14	10	18	15	10	13
11	All	Overhead Line	Wood poles	No.		5	1	501	740	630	436	35	23	21	26	43	35	30
12	All	Overhead Line	Other pole types	No.														
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km		3	2	24	12	4	19						0	
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km														
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km							5						1	0
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km														
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km														
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km														
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km														
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km														
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km														
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km														
23	HV	Subtransmission Cable	Subtransmission submarine cable	km														
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.					1	1	2							
25	HV	Zone substation Buildings	Zone substations 110kV+	No.														
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.														
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.														
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.														
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.						4								
30	HV	Zone substation switchgear	33kV RMU	No.														
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.							6							
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.					1		6						1	
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.							13							
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.					2		1							4
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.				1	1	2	3	1					1	
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	11	2	8	45	14	92	83	2	2	1	1	0	0	3
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km														
38	HV	Distribution Line	SWER conductor	km														
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km						2	27	4	9	10	7	18	12	12
40	HV	Distribution Cable	Distribution UG PILC	km					0	13	21	3	2	5	10	1	2	5
41	HV	Distribution Cable	Distribution Submarine Cable	km														
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.													2	
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.														
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.			2	9	20	69	216	41	42	43	31	38	31	26
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.							10	1	3	2	12	9	14	13
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.						2	24	1	7	6	21	4	5	14
47	HV	Distribution Transformer	Pole Mounted Transformer	No.			2	9	26	48	132	21	17	20	13	16	11	5
48	HV	Distribution Transformer	Ground Mounted Transformer	No.					7	17	113	26	38	36	41	60	60	55
49	HV	Distribution Transformer	Voltage regulators	No.														3
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.														
51	LV	LV Line	LV OH Conductor	km		1	8	13	14	2	6	0	0	1	0	0	0	0
52	LV	LV Cable	LV UG Cable	km				0	1	54	53	10	10	8	18	18	13	10
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km			4	5	5	51	34	2	2	1	2	5	2	1
54	LV	Connections	OH/UG consumer service connections	No.				1	3	1	6,261	359	351	469	446	474	547	621
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	1					11	26			5			3	
56	All	SCADA and communications	SCADA and communications equipment operating as a single sys	Lot														
57	All	Capacitor Banks	Capacitors including controls	No														
58	All	Load Control	Centralised plant	Lot														
59	All	Load Control	Relays	No					6	18	71	11	21	16	25	41	53	47
60	All	Civils	Cable Tunnels	km														

sch ref	Asset class	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	No. with default dates	Data accuracy (1–4)
10	Concrete poles / steel structure	16	29	13	4	30	52	10	25	43	21	48	197	98	51	75	224					1,719		4
11	Wood poles	30	47	43	46	42	36	29	3	11	7	17	28	29	17	21	29					2,961		4
12	Other pole types																					–		N/A
13	Subtransmission OH up to 66kV conductor	2		1				0		1							0					70		4
14	Subtransmission OH 110kV+ conductor																					–		N/A
15	Subtransmission UG up to 66kV (XLPE)	0	1	2	0		0	1						1			0					13		3
16	Subtransmission UG up to 66kV (Oil pressurised)																					–		N/A
17	Subtransmission UG up to 66kV (Gas pressurised)																					–		N/A
18	Subtransmission UG up to 66kV (PILC)																					–		N/A
19	Subtransmission UG 110kV+ (XLPE)																					–		N/A
20	Subtransmission UG 110kV+ (Oil pressurised)																					–		N/A
21	Subtransmission UG 110kV+ (Gas Pressurised)																					–		N/A
22	Subtransmission UG 110kV+ (PILC)																					–		N/A
23	Subtransmission submarine cable																					–		N/A
24	Zone substations up to 66kV				1																	5		4
25	Zone substations 110kV+																					–		N/A
26	50/66/110kV CB (Indoor)																					–		N/A
27	50/66/110kV CB (Outdoor)																					–		N/A
28	33kV Switch (Ground Mounted)																					–		N/A
29	33kV Switch (Pole Mounted)			15																		19		4
30	33kV RMU																					–		N/A
31	22/33kV CB (Indoor)																					6		4
32	22/33kV CB (Outdoor)				2								1				1					12		4
33	3.3/6.6/11/22kV CB (ground mounted)				8		12		7													40		4
34	3.3/6.6/11/22kV CB (pole mounted)					1	1							1								10		4
35	Zone Substation Transformers				2	1	1								1							14		4
36	Distribution OH Open Wire Conductor	4	2	1	3	1	3	0		1	0	5	1	0	0	1	0					285		4
37	Distribution OH Aerial Cable Conductor																					–		N/A
38	SWER conductor																					–		N/A
39	Distribution UG XLPE or PVC	14	15	5	4	4	2	1	1	5	6	8	5	11	6	7	9					203		3
40	Distribution UG PILC	8	3	5	4	0	0	0	0		0	0										82		3
41	Distribution Submarine Cable																					–		N/A
42	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers			2				1			1					6	1					13		4
43	3.3/6.6/11/22kV CB (Indoor)																					–		N/A
44	3.3/6.6/11/22kV Switches and fuses (pole mounted)	29	22	35	34	26	25	15	3	14	17	15	27	36	30	42	44					982		4
45	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	16	13	7	12	3	1	2	1	1			1									121		3
46	3.3/6.6/11/22kV RMU	9	13	12	4	4	8	1	3	5	14	16	10	18	15	14	12					242		3
47	Pole Mounted Transformer	7	9	18	15	6	4	11	3	8	8	3	9	9	9	5	12					456		4
48	Ground Mounted Transformer	43	47	37	13	33	13	11	10	7	24	21	13	34	19	26	30					834		4
49	Voltage regulators	3		2																		8		4
50	Ground Mounted Substation Housing																					–		N/A
51	LV OH Conductor		0	0		0	0	0	0	0	0		0		0							46		4
52	LV UG Cable	18	11	13	3	5	5	3	3	5	6	6	7	7	11	7	6					311		4
53	LV OH/UG Streetlight circuit	4	1	0	1	1	1	1	0		4	1	4	4	1	1	1					140		4
54	OH/UG consumer service connections	433	411	312	294	285	220	306	310	292	274	449	372	399	331	447	306				42	15,016		4
55	Protection relays (electromechanical, solid state and numeric)			11		13	2		5				1									78		4
56	SCADA and communications equipment operating as a single sys																					–		N/A
57	Capacitors including controls																					–		N/A
58	Centralised plant				1																	1		4
59	Relays	39	37	17	9	12	6	3	5		4	2	7	7	3	6	3					469		2
60	Cable Tunnels																					–		N/A

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**
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	129
13	33kV	396	85	482
14	SWER (all SWER voltages)	9	–	9
15	22kV (other than SWER)	–	–	–
16	6.6kV to 11kV (inclusive—other than SWER)	2,279	1,171	3,450
17	Low voltage (< 1kV)	1,032	1,112	2,143
18	**Total circuit length (for supply)**	3,843	2,371	6,213
19				
20	Dedicated street lighting circuit length (km)	532	537	1,069
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			57

22			
23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**
24	Urban	1,163	30%
25	Rural	2,593	67%
26	Remote only	–	–
27	Rugged only	87	2%
28	Remote and rugged	–	–
29	Unallocated overhead lines	–	–
30	**Total overhead length**	3,843	100%
31			
32		**Circuit length (km)**	**(% of total circuit length)**
33	Length of circuit within 10km of coastline or geothermal areas (where known)	1,471	24%
34		**Circuit length (km)**	**(% of total overhead length)**
35	Overhead circuit requiring vegetation management	3,843	100%

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**
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)	722	331	1,053
17	Low voltage (< 1kV)	811	302	1,113
18	**Total circuit length (for supply)**	1,686	700	2,385
19				
20	Dedicated street lighting circuit length (km)	460	223	683
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	968	57%	
25	Rural	709	42%	
26	Remote only	–	–	
27	Rugged only	9	1%	
28	Remote and rugged	–	–	
29	Unallocated overhead lines	–	–	
30	**Total overhead length**	1,686	100%	
31				
32		**Circuit length (km)**	**(% of total circuit length)**	
33	Length of circuit within 10km of coastline or geothermal areas (where known)	1,471	62%	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	1,686	100%	

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**
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	129
13	33kV	183	6	189
14	SWER (all SWER voltages)	–	–	–
15	22kV (other than SWER)	–	–	–
16	6.6kV to 11kV (inclusive—other than SWER)	1,271	553	1,825
17	Low voltage (< 1kV)	176	490	665
18	**Total circuit length (for supply)**	1,757	1,052	2,809
19				
20	Dedicated street lighting circuit length (km)	57	187	244
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	128	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**	1,757	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	1,757	100%	

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**
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

		Overhead (km)	Underground (km)	Total circuit length (km)
9				
10	**Circuit length by operating voltage (at year end)**			
11	> 66kV	–	–	–
12	50kV & 66kV	–	–	–
13	33kV	70	13	82
14	SWER (all SWER voltages)	–	–	–
15	22kV (other than SWER)	–	–	–
16	6.6kV to 11kV (inclusive—other than SWER)	285	285	570
17	Low voltage (< 1kV)	46	311	356
18	**Total circuit length (for supply)**	400	609	1,009
19				
20	Dedicated street lighting circuit length (km)	16	125	140
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			22
22				

		Circuit length (km)	(% of total overhead length)
23	**Overhead circuit length by terrain (at year end)**		
24	Urban	67	17%
25	Rural	311	78%
26	Remote only	–	–
27	Rugged only	23	6%
28	Remote and rugged	–	–
29	Unallocated overhead lines	–	–
30	**Total overhead length**	400	100%
31			

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

		Circuit length (km)	(% of total overhead length)
34			
35	Overhead circuit requiring vegetation management	400	100%

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**

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

sch ref	Location *	Number of ICPs served	Line charge revenue ($000)
8			
9	Heritage Estate (Te Anau)	140	106
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 2022**
Network / Sub-network Name	**Total Network**

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref

8	**9e(i): Consumer Connections**		
9	*Number of ICPs connected in year by consumer type*		
10	*Consumer types defined by EDB**	**Number of connections (ICPs)**	
11	Residential	900	
12	Load Group 0	1	
13	Load Group 0A	37	
14	Load Group 1A	12	
	Load Group 1	(37)	
	Load Group 2	198	
	Load Group 3	8	
	Load Group 3A	5	
	Load Group 4	3	
	Load Group 5	–	
	Street Lighting	–	
15	Distributed Unmetered Load (excluding street lighting)	1	
16	** include additional rows if needed*		
17	**Connections total**	1,128	
18			
19	**Distributed generation**		
20	Number of connections made in year	390	**connections**
21	Capacity of distributed generation installed in year	2.17	**MVA**
22	**9e(ii): System Demand**		
23			
24			
25	**Maximum coincident system demand**	**Demand at time of maximum coincident demand (MW)**	
26	GXP demand	251	
27	*plus* Distributed generation output at HV and above	58	
28	**Maximum coincident system demand**	309	
29	*less* Net transfers to (from) other EDBs at HV and above	0	
30	**Demand on system for supply to consumers' connection points**	309	
31	**Electricity volumes carried**	**Energy (GWh)**	
32	Electricity supplied from GXPs	1,134	
33	*less* Electricity exports to GXPs	49	
34	*plus* Electricity supplied from distributed generation	300	
35	*less* Net electricity supplied to (from) other EDBs	2	
36	**Electricity entering system for supply to consumers' connection points**	1,382	
37	*less* Total energy delivered to ICPs	1,307	
38	**Electricity losses (loss ratio)**	75	5.4%
39			
40	**Load factor**	0.51	
41	**9e(iii): Transformer Capacity**		
42		**(MVA)**	
43	Distribution transformer capacity (EDB owned)	942	
44	Distribution transformer capacity (Non-EDB owned, estimated)	69	
45	**Total distribution transformer capacity**	1,011	
46			
47	**Zone substation transformer capacity**	967	

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**
Network / Sub-network Name	**Dunedin Sub-network**

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref			
8	**9e(i): Consumer Connections**		
9	*Number of ICPs connected in year by consumer type*		
10	*Consumer types defined by EDB**	**Number of connections (ICPs)**	
11	Residential	305	
12	Load Group 0	–	
13	Load Group 0A	16	
14	Load Group 1A	(3)	
	Load Group 1	(47)	
	Load Group 2	28	
	Load Group 3	2	
	Load Group 3A	2	
	Load Group 4	(1)	
	Load Group 5	–	
	Street Lighting	–	
15	Distributed Unmetered Load (excluding street lighting)	1	
16	** include additional rows if needed*		
17	**Connections total**	303	
18			
19	**Distributed generation**		
20	Number of connections made in year	78	**connections**
21	Capacity of distributed generation installed in year	0.37	**MVA**

22	**9e(ii): System Demand**		
23			
24			
25	**Maximum coincident system demand**	**Demand at time of maximum coincident demand (MW)**	
26	GXP demand	159	
27	*plus* Distributed generation output at HV and above	37	
28	**Maximum coincident system demand**	197	
29	*less* Net transfers to (from) other EDBs at HV and above	–	
30	**Demand on system for supply to consumers' connection points**	197	
31	**Electricity volumes carried**	**Energy (GWh)**	
32	Electricity supplied from GXPs	706	
33	*less* Electricity exports to GXPs	0	
34	*plus* Electricity supplied from distributed generation	114	
35	*less* Net electricity supplied to (from) other EDBs	–	
36	**Electricity entering system for supply to consumers' connection points**	819	
37	*less* Total energy delivered to ICPs	780	
38	**Electricity losses (loss ratio)**	39	4.8%
39			
40	**Load factor**	0.48	

41	**9e(iii): Transformer Capacity**	
42		**(MVA)**
43	Distribution transformer capacity (EDB owned)	483
44	Distribution transformer capacity (Non-EDB owned, estimated)	43
45	**Total distribution transformer capacity**	526
46		
47	**Zone substation transformer capacity**	586

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**
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

sch ref			
9	*Number of ICPs connected in year by consumer type*		
10	*Consumer types defined by EDB**	**Number of connections (ICPs)**	
11	Residential	429	
12	Load Group 0	(1)	
13	Load Group 0A	7	
14	Load Group 1A	10	
	Load Group 1	13	
	Load Group 2	84	
	Load Group 3	2	
	Load Group 3A	2	
	Load Group 4	2	
	Load Group 5	–	
	Street Lighting	–	
15	Distributed Unmetered Load (excluding street lighting)	–	
16	** include additional rows if needed*		
17	**Connections total**	548	
18			
19	**Distributed generation**		
20	Number of connections made in year	242	**connections**
21	Capacity of distributed generation installed in year	1.32	**MVA**

22 9e(ii): System Demand

sch ref			
23			
24			
25	**Maximum coincident system demand**		**Demand at time of maximum coincident demand (MW)**
26		GXP demand	38
27	*plus*	Distributed generation output at HV and above	26
28		**Maximum coincident system demand**	65
29	*less*	Net transfers to (from) other EDBs at HV and above	0
30		**Demand on system for supply to consumers' connection points**	64

sch ref				
31	**Electricity volumes carried**		**Energy (GWh)**	
32		Electricity supplied from GXPs	194	
33	*less*	Electricity exports to GXPs	49	
34	*plus*	Electricity supplied from distributed generation	170	
35	*less*	Net electricity supplied to (from) other EDBs	3	
36		**Electricity entering system for supply to consumers' connection points**	313	
37	*less*	Total energy delivered to ICPs	291	
38		**Electricity losses (loss ratio)**	22	7.1%
39				
40		**Load factor**	0.55	

41 9e(iii): Transformer Capacity

sch ref		
42		**(MVA)**
43	Distribution transformer capacity (EDB owned)	286
44	Distribution transformer capacity (Non-EDB owned, estimated)	20
45	**Total distribution transformer capacity**	306
46		
47	**Zone substation transformer capacity**	220

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**
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

8	**9e(i): Consumer Connections**			
9	*Number of ICPs connected in year by consumer type*			
10	*Consumer types defined by EDB**	**Number of connections (ICPs)**		
11	Residential	164		
12	Load Group 0	2		
13	Load Group 0A	14		
14	Load Group 1A	5		
	Load Group 1	(3)		
	Load Group 2	86		
	Load Group 3	4		
	Load Group 3A	1		
	Load Group 4	2		
	Load Group 5	–		
	Street Lighting	–		
15	Distributed Unmetered Load (excl. Street Lighting)	–		
16	** include additional rows if needed*			
17	**Connections total**	275		
18				
19	**Distributed generation**			
20	Number of connections made in year	68	**connections**	
21	Capacity of distributed generation installed in year	0.47	**MVA**	
22	**9e(ii): System Demand**			
23				
24				
25	**Maximum coincident system demand**	**Demand at time of maximum coincident demand (MW)**		
26	GXP demand	62		
27	*plus* Distributed generation output at HV and above	2		
28	**Maximum coincident system demand**	64		
29	*less* Net transfers to (from) other EDBs at HV and above	–		
30	**Demand on system for supply to consumers' connection points**	64		
31	**Electricity volumes carried**	**Energy (GWh)**		
32	Electricity supplied from GXPs	234		
33	*less* Electricity exports to GXPs	–		
34	*plus* Electricity supplied from distributed generation	16		
35	*less* Net electricity supplied to (from) other EDBs	–		
36	**Electricity entering system for supply to consumers' connection points**	249		
37	*less* Total energy delivered to ICPs	235		
38	**Electricity losses (loss ratio)**	14	5.6%	
39				
40	**Load factor**	0.44		
41	**9e(iii): Transformer Capacity**			
42		**(MVA)**		
43	Distribution transformer capacity (EDB owned)	172		
44	Distribution transformer capacity (Non-EDB owned, estimated)	5		
45	**Total distribution transformer capacity**	177		
46				
47	**Zone substation transformer capacity**	162		

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**
Network / Sub-network Name	**Total Network**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref			
8	**10(i): Interruptions**		
9	**Interruptions by class**	**Number of interruptions**	
10	Class A (planned interruptions by Transpower)	–	
11	Class B (planned interruptions on the network)	1,060	
12	Class C (unplanned interruptions on the network)	570	
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)	2	
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**	1,633	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	418	152
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.83	197.35
27	Class C (unplanned interruptions on the network)	1.84	123.68
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)	0.00	0.00
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	0.00
34	**Total**	2.67	321.03
35			
36	**Normalised SAIFI and SAIDI**	**Normalised SAIFI**	**Normalised SAIDI**
37	Classes B & C (interruptions on the network)	2.67	321.03
38			

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**
Network / Sub-network Name	**Total Network**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

39 **10(ii): Class C Interruptions and Duration by Cause**

40

		SAIFI	SAIDI
41	**Cause**		
42	Lightning	0.02	2.76
43	Vegetation	0.14	12.72
44	Adverse weather	0.02	7.07
45	Adverse environment	0.00	1.14
46	Third party interference	0.17	14.44
47	Wildlife	0.04	5.05
48	Human error	0.32	7.25
49	Defective equipment	0.76	45.13
50	Cause unknown	0.36	28.12

51

52 **10(iii): Class B Interruptions and Duration by Main Equipment Involved**

53

		SAIFI	SAIDI
54	**Main equipment involved**		
55	Subtransmission lines	0.00	0.01
56	Subtransmission cables	–	–
57	Subtransmission other	–	–
58	Distribution lines (excluding LV)	0.63	154.50
69	Distribution cables (excluding LV)	0.16	30.75
60	Distribution other (excluding LV)	0.04	12.10

61 **10(iv): Class C Interruptions and Duration by Main Equipment Involved**

62

		SAIFI	SAIDI
63	**Main equipment involved**		
64	Subtransmission lines	0.27	13.39
65	Subtransmission cables	–	–
66	Subtransmission other	0.23	7.06
67	Distribution lines (excluding LV)	0.77	77.77
68	Distribution cables (excluding LV)	0.09	4.65
69	Distribution other (excluding LV)	0.49	20.81

70 **10(v): Fault Rate**

		Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
71	**Main equipment involved**			
72	Subtransmission lines	33	523	6.31
73	Subtransmission cables	–	88	–
74	Subtransmission other	13		
75	Distribution lines (excluding LV)	251	2,288	10.97
76	Distribution cables (excluding LV)	12	1,171	1.02
77	Distribution other (excluding LV)	170		
78	**Total**	479		

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**
Network / Sub-network Name	**Dunedin Sub-network**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref			
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)	521	
12	Class C (unplanned interruptions on the network)	229	
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**	751	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	173	56
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.79	134.62
27	Class C (unplanned interruptions on the network)	0.72	51.47
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	0.00
34	**Total**	1.52	186.08
35			
36	**Normalised SAIFI and SAIDI**	**Normalised SAIFI**	**Normalised SAIDI**
37	Classes B & C (interruptions on the network)	N/A	N/A
38			

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**
Network / Sub-network Name	**Dunedin Sub-network**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

39 **10(ii): Class C Interruptions and Duration by Cause**

40

Row	Cause	SAIFI	SAIDI
41	**Cause**		
42	Lightning	0.00	0.03
43	Vegetation	0.13	11.24
44	Adverse weather	–	–
45	Adverse environment	0.00	0.01
46	Third party interference	0.04	5.68
47	Wildlife	0.03	1.30
48	Human error	0.15	4.57
49	Defective equipment	0.32	26.93
50	Cause unknown	0.05	1.71

51

52 **10(iii): Class B Interruptions and Duration by Main Equipment Involved**

53

Row	Main equipment involved	SAIFI	SAIDI
54	**Main equipment involved**		
55	Subtransmission lines	–	–
56	Subtransmission cables	–	–
57	Subtransmission other	–	–
58	Distribution lines (excluding LV)	0.61	110.80
69	Distribution cables (excluding LV)	0.16	20.36
60	Distribution other (excluding LV)	0.03	3.45

61 **10(iv): Class C Interruptions and Duration by Main Equipment Involved**

62

Row	Main equipment involved	SAIFI	SAIDI
63	**Main equipment involved**		
64	Subtransmission lines	0.04	0.62
65	Subtransmission cables	–	–
66	Subtransmission other	0.07	0.36
67	Distribution lines (excluding LV)	0.33	34.07
68	Distribution cables (excluding LV)	0.03	2.84
69	Distribution other (excluding LV)	0.25	13.57

70 **10(v): Fault Rate**

Row	Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
71	**Main equipment involved**			
72	Subtransmission lines	12	144	8.33
73	Subtransmission cables	–	66	–
74	Subtransmission other	5		
75	Distribution lines (excluding LV)	76	731	10.40
76	Distribution cables (excluding LV)	5	331	1.51
77	Distribution other (excluding LV)	81		
78	**Total**	179		

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**
Network / Sub-network Name	**Central 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 the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

10(i): Interruptions

Interruptions by class	**Number of interruptions**
Class A (planned interruptions by Transpower)	–
Class B (planned interruptions on the network)	381
Class C (unplanned interruptions on the network)	246
Class D (unplanned interruptions by Transpower)	–
Class E (unplanned interruptions of EDB owned generation)	–
Class F (unplanned interruptions of generation owned by others)	2
Class G (unplanned interruptions caused by another disclosing entity)	–
Class H (planned interruptions caused by another disclosing entity)	–
Class I (interruptions caused by parties not included above)	–
Total	629

Interruption restoration	**≤3Hrs**	**>3hrs**
Class C interruptions restored within	166	80

SAIFI and SAIDI by class	**SAIFI**	**SAIDI**
Class A (planned interruptions by Transpower)	–	–
Class B (planned interruptions on the network)	0.92	290.46
Class C (unplanned interruptions on the network)	3.33	224.61
Class D (unplanned interruptions by Transpower)	–	–
Class E (unplanned interruptions of EDB owned generation)	–	–
Class F (unplanned interruptions of generation owned by others)	0.00	0.01
Class G (unplanned interruptions caused by another disclosing entity)	–	–
Class H (planned interruptions caused by another disclosing entity)	–	–
Class I (interruptions caused by parties not included above)	–	–
Total	4.25	515.08

Normalised SAIFI and SAIDI	**Normalised SAIFI**	**Normalised SAIDI**
Classes B & C (interruptions on the network)	N/A	N/A

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**
Network / Sub-network Name	**Central 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 the ID determination), and so is subject to the assurance report required by section 2.8.

39 **10(ii): Class C Interruptions and Duration by Cause**

40

		SAIFI	SAIDI
41	**Cause**		
42	Lightning	0.03	6.89
43	Vegetation	0.19	20.40
44	Adverse weather	0.08	26.15
45	Adverse environment	0.01	4.72
46	Third party interference	0.33	37.61
47	Wildlife	0.01	2.28
48	Human error	0.34	7.23
49	Defective equipment	1.68	73.75
50	Cause unknown	0.66	45.59

51

52 **10(iii): Class B Interruptions and Duration by Main Equipment Involved**

53

		SAIFI	SAIDI
54	**Main equipment involved**		
55	Subtransmission lines	0.00	0.04
56	Subtransmission cables	–	–
57	Subtransmission other	–	–
58	Distribution lines (excluding LV)	0.71	218.24
69	Distribution cables (excluding LV)	0.13	32.90
60	Distribution other (excluding LV)	0.07	39.28

61 **10(iv): Class C Interruptions and Duration by Main Equipment Involved**

62

		SAIFI	SAIDI
63	**Main equipment involved**		
64	Subtransmission lines	0.91	36.94
65	Subtransmission cables	–	–
66	Subtransmission other	0.62	27.85
67	Distribution lines (excluding LV)	1.21	132.88
68	Distribution cables (excluding LV)	0.10	6.84
69	Distribution other (excluding LV)	0.49	20.11

70 **10(v): Fault Rate**

		Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
71	**Main equipment involved**			
72	Subtransmission lines	19	310	6.13
73	Subtransmission cables	–	9	–
74	Subtransmission other	7		
75	Distribution lines (excluding LV)	141	1,271	11.09
76	Distribution cables (excluding LV)	3	553	0.54
77	Distribution other (excluding LV)	62		
78	**Total**	232		

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**
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 the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref			
8	**10(i): Interruptions**		
9	**Interruptions by class**	**Number of interruptions**	
10	Class A (planned interruptions by Transpower)	–	
11	Class B (planned interruptions on the network)	158	
12	Class C (unplanned interruptions on the network)	95	
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**	253	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	79	16
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.83	298.17
27	Class C (unplanned interruptions on the network)	3.90	248.36
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**	4.73	546.53
35			
36	**Normalised SAIFI and SAIDI**	**Normalised SAIFI**	**Normalised SAIDI**
37	Classes B & C (interruptions on the network)	N/A	N/A
38			

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2022**
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 the ID determination), and so is subject to the assurance report required by section 2.8.

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

Cause	SAIFI	SAIDI
Lightning	0.10	6.99
Vegetation	0.10	6.74
Adverse weather	0.04	5.02
Adverse environment	–	–
Third party interference	0.44	12.73
Wildlife	0.13	23.87
Human error	0.96	17.76
Defective equipment	1.03	71.77
Cause unknown	1.11	103.50

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	–	–
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	0.60	226.60
Distribution cables (excluding LV)	0.20	67.85
Distribution other (excluding LV)	0.02	3.72

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.20	26.59
Subtransmission cables	–	–
Subtransmission other	0.24	0.95
Distribution lines (excluding LV)	1.78	162.44
Distribution cables (excluding LV)	0.30	8.34
Distribution other (excluding LV)	1.39	50.04

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	2	70	2.86
Subtransmission cables	–	13	–
Subtransmission other	1		
Distribution lines (excluding LV)	34	285	11.93
Distribution cables (excluding LV)	4	285	1.40
Distribution other (excluding LV)	27		
Total	68		

Company Name	Aurora Energy Limited
For Year Ended	31 March 2022

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 RY22 ROI exceeded the estimated WACC used to set Aurora Energy's price path. The RY22 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 them if they exceed expenditure allowances, determined by the Commerce Commission, and rewarding them if expenditure is below the allowance.

Aurora Energy exceeded its operational expenditure (opex) and capital expenditure (capex) allowances in the regulatory periods leading up to March 2021, as it sought to address a period of underinvestment on its network. The overspends gave rise to opex and capex IRIS penalties of $15.363 mil and $1.451 mil respectively. These penalties were deducted from the company's allowable revenue calculation when setting prices for RY22.

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 . We 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 hexceeded, 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 2022 is $41.8 mil before tax. This represents a $32.3 mil increase from the previous year.

The increase was largely driven by revaluations (+$29.7mil) and higher line revenue (+$7.4 mil) offset by higher expenses in depreciation (+$2.1 mil), pass-through-costs (+$1.2 mil) and regulatory tax ($0.9 mil)

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 RAB increased by $105.6 mil over RY22. An increase of $55.7 mil on the prior disclosure year's increase of $49.9 mil. The drivers of the increase were higher commissioned assets (+$31.9 mil) and revaluations (+$29.7 mil), partially offset by higher depreciation ($2.1 mil) and disposals ($1.3 mil). There were no found assets during the disclosure year. In RY21, $2.6 mil of assets were found.

The increase in RY22 commissioned assets are due to an uplift in the value of pole replacements across the Subtransmission ($12.8 mil) and Distribution & LV Lines asset categories ($15.3 mil).

Aurora Energy has also improved project management processes, improving asset commissioning efficiency.

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 $11,181 relating to 'Expenditure or loss in regulatory profit or (loss) before tax but not deductible' is non-deductible entertainment. *The amount of $1,169,503 relating to 'Expenditure or loss deductible but not in regulatory profit / (loss) before tax' relates to payments for leases that are classified as Right of Use (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 $ 1,577,565 recorded in the current disclosure year relate to the tax effect of income spreading over 10 years on capital initiated works ($1,669,607), upward movement in provision for expected credit losses (doubtful debts) ($5,600) and decrease in employee entitlements ($97,642). *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
Aurora Energy no longer provides shared services, i.e., payroll, payables, or information technology services to Delta. Accordingly, all opex 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

Aurora Energy no longer provides shared services, i.e., payroll, payables, or information technology services to Delta. Accordingly, all non-network assets are 100% allocated to RAB.

Other network assets includes a fibre network that comprises of ducting / high speed broadband fibre utilised for communications between the Dunedin zone sub-station sites. It is assessed that for RY22, 75.5% of the network is utilised for communications between the Dunedin zone sub-station sites (RY21: 75.5%).

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's Asset Management Plan identifies contains the 10 year expenditure forecasts relating to capital 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

The CPP decision process and timing gave rise to a soft start to resourcing commitments and improvement programs in RY22. The draft CPP decision in November 2020 signalled lower non-network allowances than applied for, giving rise to the deferral of less critical RY22 SONS and business support improvement plans. Final CPP regulatory allowances were higher than the draft decision but not known until 31 March 2021.

RY22 OPEX was $5.7 mil below the CPP expenditure allowance for RY22.

RY22 network maintenance was $1.2 mil below the CPP allowance largely due to a $1.6 mil underspend on service interruptions and emergencies. Corrective and preventative maintenance was $0.5 mil overspent, whilst vegetation management ended the year $0.1 mil below the approved allowance.

RY22 non-network opex was $4.5 mil below the CPP allowance at $26.6 mil. Components of the underspend included:

- *SONS expenditure was circa $3.1 mil below allowance inclusive of underspends in network evolution (-$0.9 mil), consultancy (-$0.6 mil), payroll (-$0.1 mil) and other system operating and support costs (-$1.5 mil),*
- *Business support expenditure was circa $1.4 mil below budget inclusive of underspends in people costs (-$1.1 mil) and other business support costs (-$0.3 mil).*

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's total asset expenditure was $4.3 mil (5%) higher than forecast 5%.

Consumer connection growth reflects the continuing higher levels of development activity than recognised in the CPP decision, mainly on the Central Otago/Wanaka and Queenstown subnetworks.

System growth expenditure was higher than forecast largely due to a catch up in expenditure on prior period projects.

The asset replacement and renewal expenditure variance (-$3.6 mil) is largely due to underspends on the following network programmes:

- *Cross-arm replacements programme; and*
- *Distribution switchgear replacement programme*

We expect this underspend to catch up in future years.

Asset relocations variance was lower than forecast largely due to the Cardrona new feeder project delays due to feeder configuration changes.

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

Non-network capex was lower than expected largely due a delay in our Asset Management Systems project.

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

RY22 vegetation management and routine and corrective maintenance expenditure was within 5% of forecast for the year.

Whilst the RY22 OPEX allowance was close to application levels, the profile of the approved allowances from RY23 is such that the Commission has imposed aggressive 'efficiency' adjustments in the latter years of the 5-year CPP. In this context then, our preparation for RY22 was initially cautious which coupled with the impact of Covid-19 operating restrictions caused RY22 resourcing plans and project-based improvements to be delayed.

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
<u>*Total Revenue:*</u> *The forecast revenue from line charges was $107.112 million (RY2022 Annual Price-Setting Compliance Statement).* *In Schedule 8 (Total Network), we have reported total line charge revenue of $105.829 million. This is a difference of $1.283 million (1.2%) below target. It is generally expected that total billed line charge revenue for an assessment period will be different from target revenue due to variation in connection numbers and energy demand.* <u>*Residential Revenue:*</u> *In this assessment period, the volume of energy delivered to Residential consumers (the only consumer groups with volume-based pricing) decreased from the prior year (by 1.7%). Energy delivered to Residential connections for the year ended 31 March 2022 was 618.6 GWh compared with 629.1GWh last year.* *The average number of Residential connections increased by 1.2% during the assessment period. The average number of residential connections for the year ended 31 March 2022 was 78,090, compared with 77,158 for the year ended 31 March 2021.* *The average energy use per Residential consumer in this assessment period has decreased by 2.8% from 8,153 kWh for the year ended 31 March 2020 to 7,921 kWh in this assessment period.* <u>*General Revenue:*</u> *The average number of General connections, which are priced predominantly on the basis of demand and capacity, increased from 14,926 in RY21 to 15,186 in this assessment period (1.7%). This increase was smaller than forecast, likely reflecting the ongoing impact of the Covid 19 pandemic.* *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 (2022), 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 has been obtained / is in place for zone substations, both for the buildings and the plant and equipment contained within them. The material damage (including flood, earthquake etc.) cover for the zone substations and associated equipment is on a replacement cost basis. Material Damage Insurance cover has been obtained 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 2022

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 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

<u>Successive interruptions</u>

Aurora Energy, along with all other EDBs, received an exemption from the Commerce Commission, issued on 17 May 2021, regarding the disclosure and auditing of reliability information within Schedule 10. The information in this box is disclosed in accordance with paragraphs 6 and 7 of that exemption.

Treatment of successive interruptions between disclosure years 2021 and 2022: *We have treated successive interruptions in the same way for the 2022 disclosure year as we did for the 2021 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.*

<u>Annual Delivery Report</u>

On 9 August 2022, Aurora Energy was granted an exemption by the Commerce Commission from procuring an assurance report for clauses 1.6.3 (asset replacement and renewal) and 1.6.4 (vegetation management) of Attachment C of the Determination for the 2022 disclosure year, subject to Aurora Energy publishing the reasons for disclosing the unaudited information using the form set out in Schedule 15 Voluntary Explanatory Notes of the Determination, in its information disclosure submission for the 2022 disclosure year.

The information disclosed in this Box 1 is to meet that condition.

The reasons for disclosing unaudited information with respect to clauses 1.6.3 and 1.6.4 in tables 3 and 4 of the Annual Delivery Report, are as follows:

- *The enhanced information disclosures required by clauses 1.6.3 and 1.6.4 of Attachment C of the Determination were implemented five months after RY22 had commenced and include new requirements to produce information that we had not previously had to collect and report. As a result, we had to establish, part way through the year, new processes and controls for collecting and reporting the required information;*

- *The processes and controls we have used to compile certain quantitative information for the 2022 Annual Delivery Report, owing to the timing of publication of the Determination, were not as able to be evidenced to Audit NZ as those we have been able to develop for the quantitative information we will disclose in the Annual Delivery Report in subsequent disclosure years; and*

- *There was a risk that, because of the timing of the Determination, we could not reasonably meet the assurance standard set out in clause 2.8 of the Determination. Our inability to meet that assurance standard would not have been the result of any failure on the part of our data capture or reporting of information, but simply because the information now required was not part of our reporting processes prior to the implementation of the enhanced disclosure obligations.*

Aurora ENERGY

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 2022.

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 by virtue of DCHL being 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.	$50,654,000 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.	$889,000 This expenditure is primarily in relation to local rates that are payable to the DCC.
Dunedin International Airport Limited (DIAL)	Aurora Energy and DIAL are related by virtue of DCHL being the ultimate holding company of Aurora Energy and a shareholder of DIAL.	The primary activity of DIAL is to operate an efficient and safe airport utilising sound business principles, for the benefit of both commercial and non-commercial aviation users.	$1,000 This expenditure is in relation to venue hire fees.
Dunedin Venues Management Limited (DVML)	Aurora Energy and DVML are related because DCHL is the ultimate holding company of	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	$6,000 This expenditure is in relation to venue hire fees.

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
	Aurora Energy and DVML. DCHL is the sole shareholder of DVML.	facilitate community access to the venues for which it is responsible.	

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 92,000 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

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. The skills required to operate on, and knowledge of, our network that it has gained over years, together with the fact that there has traditionally not been any other service provider on the network means that Delta remains, at this point in time, the contractor on our network that is best placed to perform certain types of work, for example first response and fault repair.

Delta has traditionally performed vegetation management services as well. However, from 1 April 2022, vegetation management for the Queenstown subnetwork is 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.

With Unison and Connetics having now established themselves as additional 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.

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 partners) are invited to tender. Delta, plus the other FSA providers and other approved contractors participate in this external tender market.

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.

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.

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 at a zone-substation	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 Frankton 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.
Routine and corrective maintenance and inspection	Inspections of wood 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.
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 5 March 2020 when an independent valuation report was obtained.
Capital expenditure			
System growth	Upgrade of low voltage board within distribution transformer	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 high voltage feeder	Tender	The terms were last tested on 25 March 2022.

EXPENDITURE CATEGORY	REPRESENTATIVE EXAMPLE	PROCUREMENT METHOD	HOW AND WHEN ARM'S LENGTH TERMS LAST TESTED
Asset replacement and renewal	Replacement of conductor and 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.
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 heat-pumps at zone substations	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	Installation of safety hand-rail at office	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.	RY23-32	$70.7 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.

	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 RY23.				
1a.	**Pole Inspections** This programme of works encompasses the preventive inspection of poles on the Aurora Energy network.	RY23	$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.	RY23	$1.1 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.
1c.	**Zone Substation Preventive Maintenance** This programme of works encompasses the carrying out of preventive maintenance in Aurora Energy's zone substations.	RY23	$1.0 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.	RY23	$1.0 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.	RY23	$0.4 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.
1f.	**LV Enclosure Inspections** This programme of works encompasses the carrying out of preventive inspections on Aurora Energy's LV enclosures.	RY23	$0.3 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.
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.	RY23-32	$51.1 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	RY23-32	$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, 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.	RY23-32	$29.3 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.
4a.	**Possum and Cable Guard Retrofit Programme** This programme of work encompasses the retrofitting of possum guards and cable guards on the Aurora network.	RY23-26	$0.8 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.

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				

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
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.	RY23-32	$164.4 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, 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.	RY23-32	$117.3 million	Specific zone substations located across the network	Currently not indicated for supply by a related party.
2a.	**Andersons Bay Substation Rebuild** The equipment contained in the Andersons Bay substation is near-end-of-life and requires renewal. The optimum solution is for the substation to be rebuilt on the existing site.	RY23	$4.6 million	Andersons Bay, 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 switchroom building to house a new 33 kV switchboard.	RY26-28	$7.5 million	Mosgiel, Dunedin	Currently not indicated for supply by a related party.
2c.	**Green Island Substation Rebuild** The equipment contained in the Green Island substation is near-end-of-life and requires renewal.	RY23-24	$6.2 million	Green Island, 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
	The optimum solution is for the substation to be rebuilt on the existing site.				
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.	RY24-26	$5.7 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.	RY23-24	$4.7 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.	RY27-29	$5.6 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.	RY23-32	$53.4 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, and other Approved Contractors.
4.	**Distribution Conductor Replacement** This is an ongoing programme of work to replace distribution conductor that has reached end-of-life.	RY23-32	$51.3 million	Total network	This programme of works will likely be provided by a mix of FSAs, each of 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

	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
					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.	RY23-32	$40.2 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.	RY27-28	$8.9 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.	RY25-26	$9.5 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.	RY23-24	$6.6 million	Kaikorai Valley, Dunedin	Currently not indicated for supply by a related party.
6.	**Low voltage Conductor Replacement** This is an ongoing programme of work to replace LV conductor that has reached end-of-life.	RY23-32	$35.1 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

	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
					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.	RY23-32	$26.1 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.
8.	**Ancillary Distribution Sub Replacements** This is an ongoing programme of work to replace ancillary distribution substations that have reached end-of-life.	RY23-32	$21.1 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.
9.	**Ground Mounted Switchgear Replacements** This is an ongoing programme of work to replace ground mounted switchgear that has reached end-of-life.	RY23-32	$20.0 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-life. It includes pole mount to ground mount conversions of large two pole substations, which are not seismically qualified.	RY23-32	$19.8 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.

4.2 Heatmaps

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 Andersons Bay substation rebuild

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

2c Green Island substation rebuild

2d Willowbank substation renewal

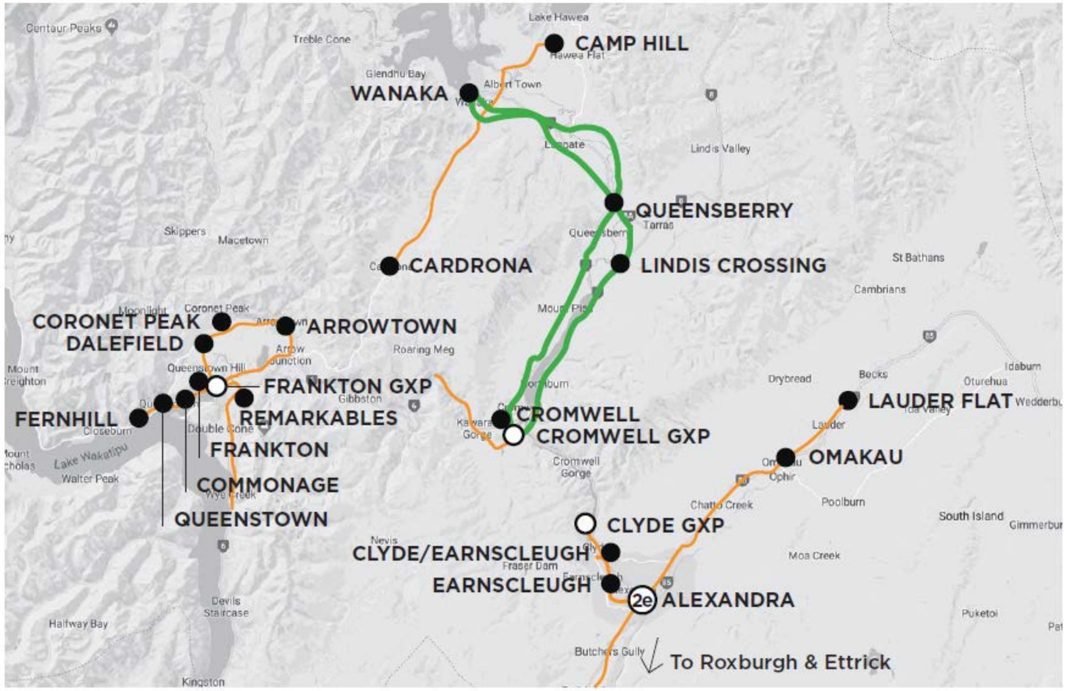
2f East Taieri substation renewal

5a Willowbank cable replacement and switchboard

5b Corstorphine cable replacement

5c Kaikorai Valley cable replacement

4.2.2 Central Otago subnetwork



Grid Exit Point   Zone Substation   66kV overhead line   33kV overhead line

Operational Expenditure:

①-④ Total network

Capital Expenditure:

① ③-④ ⑥-⑩ Total network

2e Alexandra Substation renewal

SCHEDULE 18

Certification for Year-end Disclosures

Clause 2.9.2

We, Stephen Richard Thompson and Janice Evelyn Fredric, 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

J E Fredric

Janice Evelyn Fredric

29 August 2022

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 2022 as required by the Electricity Distribution Information Disclosure Amendment Determination 2012 (Consolidated 9 December 2021)

Aurora Energy Limited (the company) is required to disclose certain information under the Electricity Distribution Information Disclosure Determination 2012 (consolidated 9 December 2021) (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 2022 (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 17 May 2021 under clause 2.11 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 (SAE) 3100 (Revised) *Assurance Engagements on Compliance*, 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*, issued by the New Zealand Auditing and Assurance Standards Board.

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 replacement or network growth) in nature. Capital expenditure in the current disclosure year totalled $72 million and assets commissioned into the RAB amounted to $93 million, compared to total network operating expenditure of $20 million. The amount of capital	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*; • 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;

Key assurance matter	How our procedures addressed the key assurance matter
expenditure is also significant relative to the RAB opening value of $540 million. Capital expenditure and assets commissioned into the RAB are a key assurance matter due to the significant judgement used by the auditor to assess whether the capital expenditure and assets commissioned into the RAB meets the definition set out in the Determination.	• reconciling the assets commissioned from the regulatory fixed asset register to the additions disclosed in the audited financial statements and investigated any reconciling items; • comparing the standard asset lives by asset category to those set out in the IM Determination and verified the spreadsheet formula used to calculate regulatory depreciation expenses is in line with the IM Determination; • testing the mathematical accuracy of the revaluation calculation performed by the company by recalculating the revaluation rate set out in the IM Determination using the relevant Consumer Price Index indices taken from Statistics New Zealand's website; and • testing a sample of disposals from the RAB that they meet the definition of a disposal in accordance with the IM Determination. 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	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

<table>
<tr><th>Key assurance matter</th><th>How our procedures addressed the key assurance matter</th></tr>
<tr><td>significant professional judgement by the auditor.</td><td>calculation with the Determination and the IM Determination; and
• 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.</td></tr>
<tr><td>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.</td><td>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 to supply to gain assurance that interruptions to supply were recorded. Internal and external information sources included works orders for contractors, media reports, and Board minutes;
• 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;</td></tr>
</table>

Key assurance matter	How our procedures addressed the key assurance matter
	• 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 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 independence and ethical requirements of Professional and Ethical Standard 1 issued by the New Zealand Auditing and Assurance Standards Board; and

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

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 engagements on the customised price-quality path annual compliance statement and the annual delivery report, and the annual audit of the company's financial statements and performance information, 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 2022