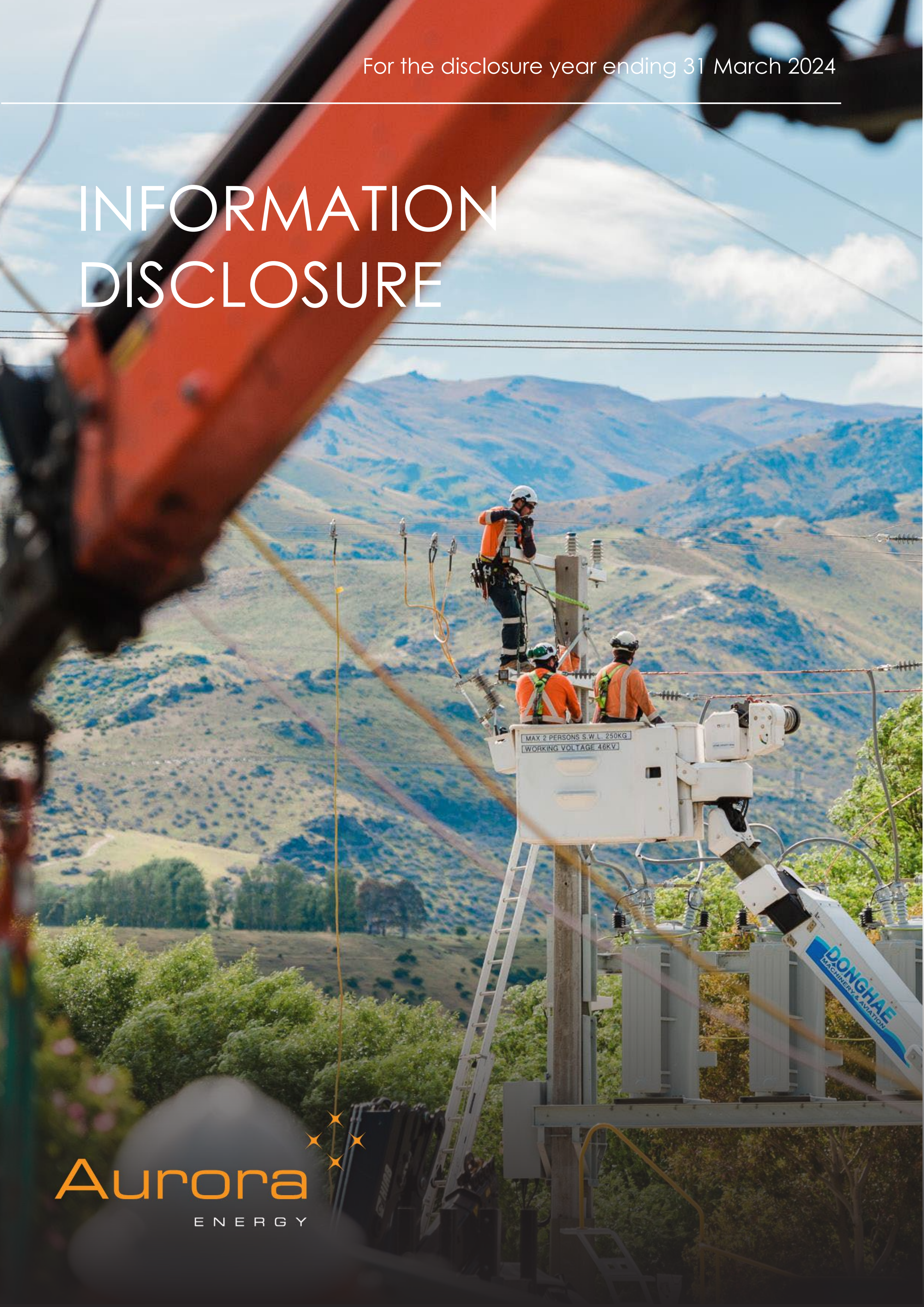
For the disclosure year ending 31 March 2024

INFORMATION DISCLOSURE



Aurora
ENERGY

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Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**

SCHEDULE 1: ANALYTICAL RATIOS

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

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

sch ref

1(i): Expenditure metrics

	Expenditure per GWh energy delivered to ICPs ($/GWh)	Expenditure per average no. of ICPs ($/ICP)	Expenditure per MW maximum coincident system demand ($/MW)	Expenditure per km circuit length ($/km)	Expenditure per MVA of capacity from EDB-owned distribution transformers ($/MVA)
Operational expenditure	33,711	504	154,105	7,604	49,025
Network	12,366	185	56,530	2,789	17,984
Non-network	21,345	319	97,574	4,815	31,041
Expenditure on assets	75,513	1,129	345,196	17,033	109,815
Network	73,394	1,097	335,509	16,555	106,734
Non-network	2,119	32	9,687	478	3,082

1(ii): Revenue metrics

	Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
Total consumer line charge revenue	100,986	1,510
Standard consumer line charge revenue	100,953	1,499
Non-standard consumer line charge revenue	105,696	73,810

1(iii): Service intensity measures

Demand density	49	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
Volume density	226	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
Connection point density	15	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
Energy intensity	14,949	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*

1(iv): Composition of regulatory income

	($000)	% of revenue
Operational expenditure	47,995	33.61%
Pass-through and recoverable costs excluding financial incentives and wash-ups	27,795	19.47%
Total depreciation	29,095	20.38%
Total revaluations	29,401	20.59%
Regulatory tax allowance	8,520	5.97%
Regulatory profit/(loss) including financial incentives and wash-ups	58,782	41.17%
Total regulatory income	142,786	

1(v): Reliability

Interruption rate	30.13	*Interruptions per 100 circuit km*

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

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

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

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sch ref		CY-2	CY-1	Current Year CY
7	**2(i): Return on Investment**			
9	**ROI – comparable to a post tax WACC**	%	%	%
10	Reflecting all revenue earned	6.98%	8.19%	7.34%
11	Excluding revenue earned from financial incentives	9.33%	6.87%	5.44%
12	Excluding revenue earned from financial incentives and wash-ups	9.33%	6.96%	5.53%
14	**Mid-point estimate of post tax WACC**	3.52%	4.88%	6.05%
15	25th percentile estimate	2.84%	4.20%	5.37%
16	75th percentile estimate	4.20%	5.56%	6.73%
19	**ROI – comparable to a vanilla WACC**			
20	Reflecting all revenue earned	7.27%	8.71%	8.04%
21	Excluding revenue earned from financial incentives	9.63%	7.38%	6.15%
22	Excluding revenue earned from financial incentives and wash-ups	9.63%	7.47%	6.23%
24	**WACC rate used to set regulatory price path**	4.57%	4.57%	4.57%
26	**Mid-point estimate of vanilla WACC**	3.82%	5.39%	6.75%
27	25th percentile estimate	3.14%	4.71%	6.07%
28	75th percentile estimate	4.50%	6.07%	7.43%

sch ref	**2(ii): Information Supporting the ROI**		($000)	
32	Total opening RAB value	736,088		
33	*plus* Opening deferred tax	(33,450)		
34	**Opening RIV**		702,638	
36	**Line charge revenue**		143,776	
38	Expenses cash outflow	75,790		
39	*add* Assets commissioned	95,696		
40	*less* Asset disposals	1,962		
41	*add* Tax payments	3,477		
42	*less* Other regulated income	(991)		
43	**Mid-year net cash outflows**		173,992	
45	**Term credit spread differential allowance**		–	
47	Total closing RAB value	830,127		
48	*less* Adjustment resulting from asset allocation	(0)		
49	*less* Lost and found assets adjustment	–		
50	*plus* Closing deferred tax	(38,492)		
51	**Closing RIV**		791,635	
53	**ROI – comparable to a vanilla WACC**			8.04%
55	Leverage (%)			42%
56	Cost of debt assumption (%)			5.97%
57	Corporate tax rate (%)			28%
59	**ROI – comparable to a post tax WACC**			7.34%

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SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

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

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

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sch ref

2(iii): Information Supporting the Monthly ROI

Opening RIV	N/A

	Line charge revenue	Expenses cash outflow	Assets commissioned	Asset disposals	Other regulated income	Monthly net cash outflows
April						–
May						–
June						–
July						–
August						–
September						–
October						–
November						–
December						–
January						–
February						–
March						–
Total	–	–	–	–	–	–

Tax payments	N/A
Term credit spread differential allowance	N/A
Closing RIV	N/A
Monthly ROI – comparable to a vanilla WACC	N/A
Monthly ROI – comparable to a post tax WACC	N/A

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

Year-end ROI – comparable to a vanilla WACC	5.43%
Year-end ROI – comparable to a post tax WACC	4.73%

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

2(v): Financial Incentives and Wash-Ups

IRIS incentive adjustment	19,401	
Purchased assets – avoided transmission charge	–	
Energy efficiency and demand incentive allowance		
Quality incentive adjustment	(567)	
Other financial incentives	–	
Financial incentives		18,834
Impact of financial incentives on ROI		1.90%
Input methodology claw-back	–	
CPP application recoverable costs	–	
Catastrophic event allowance	–	
Capex wash-up adjustment	(808)	
Transmission asset wash-up adjustment	–	
2013–15 NPV wash-up allowance	–	
Reconsideration event allowance	–	

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

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

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

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sch ref			
118	Other wash-ups	–	
119	**Wash-up costs**		(808)
120			
121	**Impact of wash-up costs on ROI**		–0.08%

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

This schedule requires information on the calculation of regulatory profit for the EDB for the disclosure year. All EDBs must complete all sections and provide explanatory comment on their regulatory profit in Schedule 14 (Mandatory Explanatory Notes).

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

sch ref				
7		**3(i): Regulatory Profit**		**($000)**
8		**Income**		
9		Line charge revenue		143,776
10	*plus*	Gains / (losses) on asset disposals		(1,962)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)		971
12				
13		**Total regulatory income**		142,786
14		**Expenses**		
15	*less*	Operational expenditure		47,995
16				
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups		27,795
18				
19		**Operating surplus / (deficit)**		66,996
20				
21	*less*	Total depreciation		29,095
22				
23	*plus*	Total revaluations		29,401
24				
25		**Regulatory profit / (loss) before tax**		67,301
26				
27	*less*	Term credit spread differential allowance		–
28				
29	*less*	Regulatory tax allowance		8,520
30				
31		**Regulatory profit/(loss) including financial incentives and wash-ups**		58,782
32				
33		**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	**($000)**	
34		**Pass through costs**		
35		Rates	1,455	
36		Commerce Act levies	406	
37		Industry levies	312	
38		CPP specified pass through costs	–	
39		**Recoverable costs excluding financial incentives and wash-ups**		
40		Electricity lines service charge payable to Transpower	24,889	
41		Transpower new investment contract charges	693	
42		System operator services	–	
43		Distributed generation allowance	–	
44		Extended reserves allowance	–	
45		Other recoverable costs excluding financial incentives and wash-ups	40	
46		**Pass-through and recoverable costs excluding financial incentives and wash-ups**		27,795
47				
48		**3(iv): Merger and Acquisition Expenditure**		
49				**($000)**
50		Merger and acquisition expenditure		–
51				
52		*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)*		
53		**3(v): Other Disclosures**		
54				**($000)**
55		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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

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

		RAB CY-4 ($000)	RAB CY-3 ($000)	RAB CY-2 ($000)	RAB CY-1 ($000)	RAB CY ($000)
	Total opening RAB value	447,072	489,854	539,722	645,301	736,088
less	**Total depreciation**	16,809	20,358	22,502	25,779	29,095
plus	**Total revaluations**	11,277	7,402	37,128	42,563	29,401
plus	**Assets commissioned**	49,227	61,073	93,006	76,873	95,696
less	**Asset disposals**	912	830	2,087	2,871	1,962
plus	**Lost and found assets adjustment**	–	2,581	–	–	–
plus	**Adjustment resulting from asset allocation**	–	–	34	–	(0)
	Total closing RAB value	489,854	539,722	645,301	736,088	830,127

4(ii): Unallocated Regulatory Asset Base

		Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
	Total opening RAB value		736,961		736,088
less					
	Total depreciation		29,132		29,095
plus					
	Total revaluations		29,436		29,401
plus					
	Assets commissioned (other than below)	59,869		59,869	
	Assets acquired from a regulated supplier	–		–	
	Assets acquired from a related party	35,827		35,827	
	Assets commissioned		95,696		95,696
less					
	Asset disposals (other than below)	1,962		1,962	
	Asset disposals to a regulated supplier	–		–	
	Asset disposals to a related party	–		–	
	Asset disposals		1,962		1,962
plus	**Lost and found assets adjustment**		–		
plus	**Adjustment resulting from asset allocation**				(0)
	Total closing RAB value		830,999		830,127

** 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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For Year Ended	31 March 2024

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

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

sch ref						
51						
52	**4(iii): Calculation of Revaluation Rate and Revaluation of Assets**					
53						
54		CPI_4				1,267
55		CPI_4^{-4}				1,218
56		Revaluation rate (%)				4.02%
57						
58			**Unallocated RAB ***		**RAB**	
59			**($000)**	**($000)**	**($000)**	**($000)**
60		Total opening RAB value	736,961		736,088	
61	*less*	Opening value of fully depreciated, disposed and lost assets	5,273		5,273	
62						
63		Total opening RAB value subject to revaluation	731,688		730,815	
64		**Total revaluations**		29,436		29,401
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**		37,319		37,319
69	*plus*	Capital expenditure	96,754		96,754	
70	*less*	Assets commissioned	95,696		95,696	
71	*plus*	Adjustment resulting from asset allocation			–	
72		**Works under construction - current disclosure year**		38,377		38,377
73						
74		Highest rate of capitalised finance applied				4.66%
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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

76 ### 4(v): Regulatory Depreciation

sch ref		Unallocated RAB *		RAB	
78		($000)	($000)	($000)	($000)
79	Depreciation - standard	27,021		27,021	
80	Depreciation - no standard life assets	2,111		2,074	
81	Depreciation - modified life assets	–		–	
82	Depreciation - alternative depreciation in accordance with CPP	–		–	
83	**Total depreciation**		29,132		29,095

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**	40,212	27,907	119,363	225,618	176,310	78,226	40,056	22,142	6,254	736,088
100	*less*	Total depreciation	1,332	840	4,616	6,657	5,816	2,938	1,933	2,888	2,074	29,095
101	*plus*	Total revaluations	1,616	1,123	4,741	9,023	7,089	3,147	1,592	843	227	29,401
102	*plus*	Assets commissioned	4,042	10,200	16,921	35,932	10,571	7,244	7,879	1,155	1,751	95,696
103	*less*	Asset disposals	46	–	–	1,324	89	–	503	–	–	1,962
104	*plus*	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
105	*plus*	Adjustment resulting from asset allocation	–	–	–	–	–	–	–	–		–
106	*plus*	Asset category transfers	–	–	–	–	–	–	–	–	–	–
107		**Total closing RAB value**	44,492	38,389	136,409	262,592	188,066	85,679	47,091	21,252	6,158	830,127
109		**Asset Life**										
110		Weighted average remaining asset life	30.2	33.2	25.9	33.7	30.3	26.6	20.5	7.7	3.0	(years)
111		Weighted average expected total asset life	50.1	54.4	51.3	54.2	52.9	50.2	39.6	18.4	7.9	(years)

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

This schedule requires information on the calculation of the regulatory tax allowance. This information is used to calculate regulatory profit/loss in Schedule 3 (regulatory profit). EDBs must provide explanatory commentary on the information disclosed in this schedule, in Schedule 14 (Mandatory Explanatory Notes).

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

sch ref					
7	**5a(i): Regulatory Tax Allowance**			**($000)**	
8		**Regulatory profit / (loss) before tax**		67,301	
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	46		*
12		Amortisation of initial differences in asset values	4,897		
13		Amortisation of revaluations	5,740		
14				10,683	
15					
16	*less*	Total revaluations	29,401		
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	1,042		*
20		Notional deductible interest	17,114		
21				47,558	
22					
23		**Regulatory taxable income**		30,427	
24					
25	*less*	Utilised tax losses	–		
26		Regulatory net taxable income		30,427	
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**		8,520	
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	68,118		
37	*less*	Amortisation of initial differences in asset values	4,897		
38	*plus*	Adjustment for unamortised initial differences in assets acquired	–		
39	*less*	Adjustment for unamortised initial differences in assets disposed	305		
40		Closing unamortised initial differences in asset values		62,916	
41					
42		Opening weighted average remaining useful life of relevant assets (years)		14	
43					

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

This schedule requires information on the calculation of the regulatory tax allowance. This information is used to calculate regulatory profit/loss in Schedule 3 (regulatory profit). EDBs must provide explanatory commentary on the information disclosed in this schedule, in Schedule 14 (Mandatory Explanatory Notes).

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

sch ref

sch ref				
44	**5a(iv): Amortisation of Revaluations**			**($000)**
45				
46		Opening sum of RAB values without revaluations	611,837	
47				
48		Adjusted depreciation	23,355	
49		Total depreciation	29,095	
50		Amortisation of revaluations		5,740
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**	(33,450)	
61				
62	*plus*	Tax effect of adjusted depreciation	6,539	
63				
64	*less*	Tax effect of tax depreciation	11,834	
65				
66	*plus*	Tax effect of other temporary differences*	1,378	
67				
68	*less*	Tax effect of amortisation of initial differences in asset values	1,371	
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	(245)	
73				
74	*plus*	Deferred tax cost allocation adjustment	0	
75				
76		**Closing deferred tax**		(38,492)
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**	453,773	
84	*less*	Tax depreciation	42,264	
85	*plus*	Regulatory tax asset value of assets commissioned	106,512	
86	*less*	Regulatory tax asset value of asset disposals	1,086	
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**		516,935

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SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

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

sch ref		($000)	($000)	
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	3,372		
13	Vegetation management	4,523		
14	Routine and corrective maintenance and inspection	7,694		
15	Asset replacement and renewal (opex)	–		
16	**Network opex**		15,589	
17	Business support	377		
18	System operations and network support - other	106		
19	Non-network solutions provided by a related party or third party (Not Required before DY2025)	–		*Not Required before DY2025*
20	**Operational expenditure**		16,072	
21	Consumer connection	4,750		
22	System growth	3,856		
23	Asset replacement and renewal (capex)	27,819		
24	Asset relocations	1,384		
25	Quality of supply	1,088		
26	Legislative and regulatory	–		
27	Other reliability, safety and environment	–		
28	**Expenditure on non-network assets**		62	
29	**Expenditure on assets**		38,959	
30	Cost of financing		830	
31	Value of capital contributions		2,976	
32	Value of vested assets		–	
33	**Capital Expenditure**		36,813	
34	**Total expenditure**		52,885	
35				
36	**Other related party transactions**		1,231	

37 5b(iii): Total Opex and Capex Related Party Transactions

sch ref	Name of related party	Nature of opex or capex service provided	Total value of transactions ($000)
38	**Name of related party**	**Nature of opex or capex service provided**	**Total value of transactions ($000)**
39	Delta Utility Services Ltd	Service interruptions and emergencies	3,372
40	Delta Utility Services Ltd	Vegetation management	4,523
41	Delta Utility Services Ltd	Routine and corrective maintenance and inspection	7,694
42	Delta Utility Services Ltd	System operations and network support - other	106
43	Delta Utility Services Ltd	Business support	290
44	Dunedin City Council	Business support	87
45	Delta Utility Services Ltd	Consumer connection	4,750
46	Delta Utility Services Ltd	System growth	3,856
47	Delta Utility Services Ltd	Asset replacement and renewal (capex)	27,819
48	Delta Utility Services Ltd	Asset relocations	1,384
49	Delta Utility Services Ltd	Quality of supply	1,088
50	Delta Utility Services Ltd	Expenditure on non-network assets	62
51			
52			
53			
54	**Total value of related party transactions**		55,031
55	** include additional rows if needed*		

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**

SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

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

sch ref

7

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

9

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

17

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

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

Company Name	Aurora Energy Limited	
For Year Ended	31 March 2024	

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref

7 **5d(i): Operating Cost Allocations**

sch ref		Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
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		3,408			
12	Not directly attributable		–		–	
13	**Total attributable to regulated service**		3,408			
14	**Vegetation management**					
15	Directly attributable		4,511			
16	Not directly attributable		–		–	
17	**Total attributable to regulated service**		4,511			
18	**Routine and corrective maintenance and inspection**					
19	Directly attributable		9,687			
20	Not directly attributable		–		–	
21	**Total attributable to regulated service**		9,687			
22	**Asset replacement and renewal**					
23	Directly attributable		–			
24	Not directly attributable		–		–	
25	**Total attributable to regulated service**		–			
26	**Non-network solutions provided by a related party or third party** *Not required before DY2025*					
27	Directly attributable					
28	Not directly attributable				–	
29	**Total attributable to regulated service**		–			
30	**System operations and network support**					
31	Directly attributable		16,180			
32	Not directly attributable		–		–	
33	**Total attributable to regulated service**		16,180			
34	**Business support**					
35	Directly attributable		14,209			
36	Not directly attributable		–		–	
37	**Total attributable to regulated service**		14,209			
38						
39	**Operating costs directly attributable**		47,995			
40	**Operating costs not directly attributable**	–	–	–	–	–
41	**Operational expenditure**		47,995			
42						

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref

5d(ii): Other Cost Allocations

	($000)
Pass through and recoverable costs	
Pass through costs	
Directly attributable	2,173
Not directly attributable	–
Total attributable to regulated service	2,173
Recoverable costs	
Directly attributable	25,622
Not directly attributable	–
Total attributable to regulated service	25,622

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

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

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

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

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

† include additional rows if needed

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**

SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

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

sch ref

5e(i): Regulated Service Asset Values

	Value allocated ($000s) Electricity distribution services
Subtransmission lines	
Directly attributable	44,492
Not directly attributable	–
Total attributable to regulated service	44,492
Subtransmission cables	
Directly attributable	38,389
Not directly attributable	–
Total attributable to regulated service	38,389
Zone substations	
Directly attributable	136,409
Not directly attributable	–
Total attributable to regulated service	136,409
Distribution and LV lines	
Directly attributable	262,592
Not directly attributable	–
Total attributable to regulated service	262,592
Distribution and LV cables	
Directly attributable	188,066
Not directly attributable	–
Total attributable to regulated service	188,066
Distribution substations and transformers	
Directly attributable	85,679
Not directly attributable	–
Total attributable to regulated service	85,679
Distribution switchgear	
Directly attributable	47,091
Not directly attributable	–
Total attributable to regulated service	47,091
Other network assets	
Directly attributable	18,550
Not directly attributable	2,702
Total attributable to regulated service	21,252
Non-network assets	
Directly attributable	6,158
Not directly attributable	–
Total attributable to regulated service	6,158
Regulated service asset value directly attributable	827,425
Regulated service asset value not directly attributable	2,702
Total closing RAB value	830,127

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

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

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

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

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**

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

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

sch ref			($000)	($000)
7		**6a(i): Expenditure on Assets**	**($000)**	**($000)**
8		Consumer connection		19,234
9		System growth		18,139
10		Asset replacement and renewal		61,425
11		Asset relocations		3,677
12		Reliability, safety and environment:		
13		Quality of supply	2,017	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	–	
16		**Total reliability, safety and environment**		2,017
17		**Expenditure on network assets**		104,492
18		Expenditure on non-network assets		3,017
19				
20		**Expenditure on assets**		107,509
21	*plus*	Cost of financing		830
22	*less*	Value of capital contributions		11,585
23	*plus*	Value of vested assets		–
24				
25		**Capital expenditure**		96,754
26		**6a(ii): Subcomponents of Expenditure on Assets (where known)**		**($000)**
27		Energy efficiency and demand side management, reduction of energy losses		–
28		Overhead to underground conversion		–
29		Research and development		–
31		**6a(iii): Consumer Connection**		
32		*Consumer types defined by EDB**	**($000)**	**($000)**
33		All consumers	19,234	
34				
35				
36				
37				
38		** include additional rows if needed*		
39		**Consumer connection expenditure**		19,234
40				
41	*less*	Capital contributions funding consumer connection expenditure	9,023	
42		**Consumer connection less capital contributions**		10,211

sch ref			System Growth	Asset Replacement and Renewal
43		**6a(iv): System Growth and Asset Replacement and Renewal**		
44			**System Growth**	**Asset Replacement and Renewal**
45			**($000)**	**($000)**
46		Subtransmission	7,380	116
47		Zone substations	5,440	7,291
48		Distribution and LV lines	2,402	38,881
49		Distribution and LV cables	572	4,089
50		Distribution substations and transformers	1,512	3,044
51		Distribution switchgear	830	7,692
52		Other network assets	3	312
53		**System growth and asset replacement and renewal expenditure**	18,139	61,425
54	*less*	Capital contributions funding system growth and asset replacement and renewal	–	–
55		**System growth and asset replacement and renewal less capital contributions**	18,139	61,425
56				

sch ref			($000)	($000)
57		**6a(v): Asset Relocations**		
58		*Project or programme**	**($000)**	**($000)**
59		CFR12657 Wanaka-Mount Aspiring	388	
60		CFR12097 Ranch Royal Estate	345	
61		CFR12196 Lake McKay	306	
62				
63				
64		** include additional rows if needed*		
65		All other projects or programmes - asset relocations	2,638	
66		**Asset relocations expenditure**		3,677
67	*less*	Capital contributions funding asset relocations	2,562	
68		**Asset relocations less capital contributions**		1,115

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**

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

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

sch ref				
69				
70		**6a(vi): Quality of Supply**		
71		*Project or programme**	**($000)**	**($000)**
72		Camp Hill 2MVA generator	589	
73		Pisa Mooring network upgrade	461	
74		New Reclosers Central	308	
75		Upper Clutha special protection scheme	229	
76				
77		** include additional rows if needed*		
78		All other projects programmes - quality of supply	429	
79		**Quality of supply expenditure**		2,017
80	*less*	Capital contributions funding quality of supply	–	
81		**Quality of supply less capital contributions**		2,017
82		**6a(vii): Legislative and Regulatory**		
83		*Project or programme**	**($000)**	**($000)**
84				
85				
86				
87				
88				
89		** include additional rows if needed*		
90		All other projects or programmes - legislative and regulatory		
91		**Legislative and regulatory expenditure**		–
92	*less*	Capital contributions funding legislative and regulatory		
93		**Legislative and regulatory less capital contributions**		–
94		**6a(viii): Other Reliability, Safety and Environment**		
95		*Project or programme**	**($000)**	**($000)**
96				
97				
98				
99				
100				
101		** include additional rows if needed*		
102		All other projects or programmes - other reliability, safety and environment		
103		**Other reliability, safety and environment expenditure**		–
104	*less*	Capital contributions funding other reliability, safety and environment		
105		**Other reliability, safety and environment less capital contributions**		–
106				
107		**6a(ix): Non-Network Assets**		
108		**Routine expenditure**		
109		*Project or programme**	**($000)**	**($000)**
110		Right-of-use assets	1,220	
111				
112				
113				
114				
115		** include additional rows if needed*		
116		All other projects or programmes - routine expenditure	60	
117		**Routine expenditure**		1,280
118		**Atypical expenditure**		
119		*Project or programme**	**($000)**	**($000)**
120		Asset management system	1,685	
121				
122				
123				
124				
125		** include additional rows if needed*		
126		All other projects or programmes - atypical expenditure	52	
127		**Atypical expenditure**		1,737
128				
129		**Expenditure on non-network assets**		3,017

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**

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

This schedule requires a breakdown of operational expenditure incurred in the disclosure year.

EDBs must provide explanatory comment on their operational expenditure in Schedule 14 (Explanatory notes to templates). This includes explanatory comment on any atypical operational expenditure and assets replaced or renewed as part of asset replacement and renewal operational expenditure, and additional information on insurance.

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

sch ref				
7	**6b(i): Operational Expenditure** *Required for DY2024 and DY2025 only*		**($000)**	**($000)**
8	Service interruptions and emergencies		3,408	
9	Vegetation management		4,511	
10	Routine and corrective maintenance and inspection		9,687	
11	Asset replacement and renewal		–	
12	**Network opex**			17,606
13	Non-network solutions provided by a related party or third party	*Required for DY2025 only*		
14	System operations and network support		16,180	
15	Business support		14,209	
16	**Non-network opex**			30,389
17				
18	**Operational expenditure**			47,995
19	**6b(i): Operational Expenditure** *Not Required before DY2026*		**($000)**	**($000)**
20	Service interruptions and emergencies:			
21	Vegetation-related			
22	Other			
23	**Total service interruptions and emergencies**		–	
24	Vegetation management:			
25	Assessment and notification costs			
26	Felling or trimming vegetation - in-zone			
27	Felling or trimming vegetation - out-of-zone			
28	Other			
29	**Total vegetation management**		–	
30				
31	Routine and corrective maintenance and inspection:			
32	Asset replacement and renewal			
33	**Network opex**			–
34	Non-network solutions provided by a related party or third party			
35	System operations and network support			
36	Business support			

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**

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

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

sch ref		
37	**Non-network opex**	–
38		
39	**Operational expenditure**	–
40	**6b(ii): Subcomponents of Operational Expenditure (where known)**	
41	Energy efficiency and demand side management, reduction of energy losses	–
42	Direct billing*	–
43	Research and development	–
44	Insurance	736
45	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*	

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**

SCHEDULE 7: COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE

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

sch ref		Target ($000) [1]	Actual ($000)	% variance
7	**7(i): Revenue**			
8	Line charge revenue	140,874	143,776	2%
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	13,670	19,234	41%
11	System growth	13,499	18,139	34%
12	Asset replacement and renewal	59,277	61,425	4%
13	Asset relocations	4,484	3,677	(18%)
14	Reliability, safety and environment:			
15	Quality of supply	1,682	2,017	20%
16	Legislative and regulatory	–	–	–
17	Other reliability, safety and environment	–	–	–
18	**Total reliability, safety and environment**	1,682	2,017	20%
19	**Expenditure on network assets**	92,612	104,492	13%
20	Expenditure on non-network assets	2,456	3,017	23%
21	Expenditure on assets	95,068	107,509	13%
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	3,447	3,408	(1%)
24	Vegetation management	3,927	4,511	15%
25	Routine and corrective maintenance and inspection	13,387	9,687	(28%)
26	Asset replacement and renewal	–	–	–
27	**Network opex**	20,761	17,606	(15%)
28	Non-network solutions provided by a related party or third party *Not Required before DY2025*	–	–	–
29	System operations and network support	15,506	16,180	4%
30	Business support	15,324	14,209	(7%)
31	**Non-network opex**	30,830	30,389	(1%)
32	**Operational expenditure**	51,591	47,995	(7%)
33	**7(iv): Subcomponents of Expenditure on Assets (where known)**			
34	Energy efficiency and demand side management, reduction of energy losses	–	–	–
35	Overhead to underground conversion	–	–	–
36	Research and development	–	–	–
37				
38	**7(v): Subcomponents of Operational Expenditure (where known)**			
39	Energy efficiency and demand side management, reduction of energy losses	–	–	–
40	Direct billing	–	–	–
41	Research and development	–	–	–
42	Insurance	–	736	–
43				

44 *1 From the nominal dollar target revenue for the disclosure year disclosed under clause 2.4.3(3) of this determination*

45 *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 2024**
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.
EDBs should feel free to adjust the page break of this schedule to assist with readibility if needed.

sch ref

8(i): Billed Quantities by Price Component

Consumer group name or price category code	Standardised connection types	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)
Residential	Residential	Standard	79,726	675,875
Load Group 0	General	Standard	319	125
Load Group 0A	General	Standard	716	2,222
Load Group 1A	General	Standard	925	3,375
Load Group 1	General	Standard	5,653	44,072
Load Group 2	General	Standard	7,278	284,897
Load Group 2	General	Non-standard	0	–
Load Group 3	General	Standard	242	60,957
Load Group 3	General	Non-standard	0	–
Load Group 3A	General	Standard	194	89,104
Load Group 3A	General	Non-standard	0	–
Load Group 4	General	Standard	154	189,422
Load Group 4	General	Non-standard	1	4,359
Load Group 5	General	Standard	8	57,636
Load Group 5	General	Non-standard	1	5,576
Street Lighting	General	Standard	12	6,099
DUML, excl Street Lighting	General	Standard	–	4
Distributed Generation (Large)	General	Non-standard	12	–
Add extra rows for additional consumer groups or price category codes as necessary				
		Standard consumer totals	95,227	1,413,788
		Non-standard consumer totals	14	9,935
		Total for all consumers	95,241	1,423,723

Billed quantities by price component *Not Required after DY2024*

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.)	Days	Lamp	kWh	kVA	kVA x km	kW	kVA	Days	kWh	kVA	kW
Residential	29,179,585	–	675,875,387	–	–	–	–	–	675,875,387	–	–
Load Group 0	116,802	–	–	102	–	–	–	116,802	–	–	–
Load Group 0A	262,105	–	–	354	–	–	–	64,755	–	–	–
Load Group 1A	338,533	–	–	2,706,768	–	331,670	–	–	–	2,706,768	331,670
Load Group 1	2,069,099	–	–	31,016,025	–	4,929,656	–	–	–	31,016,025	4,929,656
Load Group 2	2,663,707	–	–	131,842,748	–	17,377,102	(511)	–	–	131,842,748	17,377,102
Load Group 2	33	–	–	–	–	–	–	–	–	–	–
Load Group 3	88,491	–	–	16,901,417	273,719,866	3,326,552	(98)	–	–	16,901,417	3,326,552
Load Group 3	24	–	–	–	–	–	–	–	–	–	–
Load Group 3A	71,152	–	–	21,229,745	307,667,128	5,232,873	(264)	–	–	21,229,745	5,232,873
Load Group 3A	24	–	–	–	–	–	–	–	–	–	–
Load Group 4	56,200	–	–	39,258,645	611,060,120	9,781,120	96,092	–	–	39,258,645	9,781,120
Load Group 4	367	–	–	–	–	–	–	367	–	–	–
Load Group 5	2,950	–	–	8,764,896	111,496,789	2,305,296	8,167	–	–	8,764,896	2,305,296
Load Group 5	367	–	–	–	–	–	–	367	–	–	–
Street Lighting	732	2,873,778	1,664,233	–	–	–	–	732	1,664,233	–	–
DUML, excl Street Lighting	–	–	4,030	–	–	–	–	–	4,030	–	–
Distributed Generation (Large)	–	–	–	–	–	–	–	–	–	–	–
Standard consumer totals	34,849,356	2,873,778	677,543,650	251,720,700	1,303,943,903	43,284,269	103,385	182,289	677,543,650	251,720,244	43,284,269
Non-standard consumer totals	815	–	–	–	–	–	–	734	–	–	–
Total for all consumers	34,850,171	2,873,778	677,543,650	251,720,700	1,303,943,903	43,284,269	103,385	183,023	677,543,650	251,720,244	43,284,269

Billed quantities by price component *Not Required before DY2025*

Standardised price component	[Select one]		[Select one]		[Select one]		[Select one]	
EDB defined price component								
	Distribution billed quantity	**Transmission billed quantity**	**Distribution billed quantity**	**Transmission billed quantity**	**Distribution billed quantity**	**Transmission billed quantity**	**Distribution billed quantity**	**Transmission billed quantity**
Residential								
Load Group 0								
Load Group 0A								
Load Group 1A								
Load Group 1								
Load Group 2								
Load Group 2								
Load Group 3								
Load Group 3								
Load Group 3A								
Load Group 3A								
Load Group 4								
Load Group 4								
Load Group 5								
Load Group 5								
Street Lighting								
DUML, excl Street Lighting								
Distributed Generation (Large)								
Standard consumer totals	–	–	–	–	–	–	–	–
Non-standard consumer totals	–	–	–	–	–	–	–	–
Total for all consumers	–	–	–	–	–	–	–	–

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

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

Consumer group name or price category code	Standardised connection types	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Total distribution line charge revenue *Not Required after DY2024*	Total transmission line charge revenue *Not Required after DY2024*
Residential	Residential	Standard	$85,829	59,736	26,092
Load Group 0	General	Standard	$130	57	72
Load Group 0A	General	Standard	$640	252	388
Load Group 1A	General	Standard	$442	345	98
Load Group 1	General	Standard	$5,642	4,236	1,406
Load Group 2	General	Standard	$23,849	15,863	7,986
Load Group 2	General	Non-standard	–	–	–
Load Group 3	General	Standard	$5,184	3,562	1,622
Load Group 3	General	Non-standard	–	–	–
Load Group 3A	General	Standard	$6,599	4,670	1,929
Load Group 3A	General	Non-standard	–	–	–
Load Group 4	General	Standard	$11,694	7,545	4,149
Load Group 4	General	Non-standard	$137	84	53
Load Group 5	General	Standard	$1,946	1,052	895
Load Group 5	General	Non-standard	$210	98	111
Street Lighting	General	Standard	$773	572	200
DUML, excl Street Lighting	General	Standard	$0	0	0
Distributed Generation (Large)	General	Non-standard	$703	703	–
Add extra rows for additional consumer groups or price category codes as necessary					
		Standard consumer totals	$142,726	$97,890	$44,836
		Non-standard consumer totals	$1,050	$886	$164
		Total for all consumers	$143,776	$98,777	$45,000
				Check	**OK**

Line charge revenues ($000) by price component *Not Required after DY2024*

Price component	Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Period Demand (Distribution)	Transformer Lease, Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Transmission)
Rate (eg, $ per day, $ per kWh, etc.)	$ / annum	$ / Lamp	$ / kWh	$ / kVA	$ / kVA x km	$ / kW	$ / kVA	$ / annum	$ / kWh	$ / kVA	$ / kW
Residential	$0	–	$59,736	–	–	–	–	$13,034	$13,058	–	–
Load Group 0	$57	–	–	–	–	–	–	$72	–	–	–
Load Group 0A	$252	–	–	–	–	–	–	$388	–	–	–
Load Group 1A	$18	–	–	$124	–	$203	–	–	–	$55	$43
Load Group 1	$110	–	–	$912	–	$3,214	($0)	–	–	$692	$713
Load Group 2	$263	–	–	$5,358	–	$10,248	($6)	–	–	$4,691	$3,295
Load Group 2	–	–	–	–	–	–	–	–	–	–	–
Load Group 3	$149	–	–	$1,158	$323	$1,936	($4)	–	–	$1,123	$498
Load Group 3	–	–	–	–	–	–	–	–	–	–	–
Load Group 3A	$120	–	–	$872	$366	$3,315	($3)	–	–	$1,280	$649
Load Group 3A	–	–	–	–	–	–	–	–	–	–	–
Load Group 4	$345	–	–	$1,159	$723	$4,490	$828	–	–	$2,436	$1,713
Load Group 4	$84	–	–	–	–	–	–	$53	–	–	–
Load Group 5	$14	–	–	$82	$147	$714	$95	–	–	$534	$361
Load Group 5	$98	–	–	–	–	–	–	$111	–	–	–
Street Lighting	$435	$91	$46	–	–	–	–	$130	$70	–	–
DUML, excl Street Lighting	$0	–	$0	–	–	–	–	–	$0	–	–
Distributed Generation (Large)	$703	–	–	–	–	–	–	–	–	–	–
Standard consumer totals	$1,762	$91	$59,783	$9,665	$1,558	$24,121	$910	$13,625	$13,128	$10,810	$7,272
Non-standard consumer totals	$886	–	–	–	–	–	–	$164	–	–	–
Total for all consumers	$2,648	$91	$59,783	$9,665	$1,558	$24,121	$910	$13,789	$13,128	$10,810	$7,272

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

	Total distribution line charge revenue	Total transmission line charge revenue
Residential	–	–
Load Group 0	–	–
Load Group 0A	–	–
Load Group 1A	–	–
Load Group 1	–	–
Load Group 2	–	–
Load Group 2	–	–
Load Group 3	–	–
Load Group 3	–	–
Load Group 3A	–	–
Load Group 3A	–	–
Load Group 4	–	–
Load Group 4	–	–
Load Group 5	–	–
Load Group 5	–	–
Street Lighting	–	–
DUML, excl Street Lighting	–	–
Distributed Generation (Large)	–	–
Standard consumer totals	–	–
Non-standard consumer totals	–	–
Total for all consumers	–	–
	Check	**Error**

Not Required before DY2025

Line charge revenues ($000) by price component *Not Required before DY2025*

Standardised price component	[Select one]			[Select one]			[Select one]			[Select one]		
EDB defined price component												
	Distribution line charge revenue	**Transmission line charge revenue**	**Total line charge revenue (distribution and transmission)**	**Distribution line charge revenue**	**Transmission line charge revenue**	**Total line charge revenue (distribution and transmission)**	**Distribution line charge revenue**	**Transmission line charge revenue**	**Total line charge revenue (distribution and transmission)**	**Distribution line charge revenue**	**Transmission line charge revenue**	**Total line charge revenue (distribution and transmission)**
Residential			–			–			–			–
Load Group 0			–			–			–			–
Load Group 0A			–			–			–			–
Load Group 1A			–			–			–			–
Load Group 1			–			–			–			–
Load Group 2			–			–			–			–
Load Group 2			–			–			–			–
Load Group 3			–			–			–			–
Load Group 3			–			–			–			–
Load Group 3A			–			–			–			–
Load Group 3A			–			–			–			–
Load Group 4			–			–			–			–
Load Group 4			–			–			–			–
Load Group 5			–			–			–			–
Load Group 5			–			–			–			–
Street Lighting			–			–			–			–
DUML, excl Street Lighting			–			–			–			–
Distributed Generation (Large)			–			–			–			–
Standard consumer totals	–	–	–	–	–	–	–	–	–	–	–	–
Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–	–	–
Total for all consumers	–	–	–	–	–	–	–	–	–	–	–	–

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

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	8

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**
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.
EDBs should feel free to adjust the page break of this schedule to assist with readibility if needed.

sch ref

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

sch ref	Consumer group name or price category code	Standardised connection types	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	49,830	427,142
16	Load Group 0	General	Standard	102	44
17	Load Group 0A	General	Standard	177	670
18	Load Group 1A	General	Standard	400	1,593
19	Load Group 1	General	Standard	2,794	21,075
20	Load Group 2	General	Standard	3,177	130,259
21	Load Group 2	General	Non-standard	–	–
22	Load Group 3	General	Standard	111	32,034
23	Load Group 3	General	Non-standard	–	–
	Load Group 3A	General	Standard	94	51,040
	Load Group 3A	General	Non-standard	–	–
	Load Group 4	General	Standard	75	98,512
	Load Group 4	General	Non-standard	–	–
	Load Group 5	General	Standard	6	46,223
	Load Group 5	General	Non-standard	–	–
	Street Lighting	General	Standard	2	4,434
	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**	56,768	813,029
27			**Non-standard consumer totals**	1	–
28			**Total for all consumers**	56,769	813,029

Billed quantities by price component *Not Required after DY2024*

sch ref	Price component	Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Period Demand (Distribution)	Transformer Lease, Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Transmission)
13	Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	Days	Lamp	kWh	kVA	kVA x km	kW	kVA	Days	kWh	kVA	kW
15	Residential	18,237,794	–	427,141,523	–	–	–	–	–	427,141,523	–	–
16	Load Group 0	37,275	–	–	102	–	–	–	37,275	–	–	–
17	Load Group 0A	64,755	–	–	354	–	–	–	64,755	–	–	–
18	Load Group 1A	146,235	–	–	1,169,880	–	142,686	–	–	–	1,169,880	142,686
19	Load Group 1	1,022,624	–	–	15,334,785	–	2,359,083	–	–	–	15,334,785	2,359,083
20	Load Group 2	1,162,700	–	–	59,488,962	–	8,236,220	–	–	–	59,488,962	8,236,220
21	Load Group 2 (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
22	Load Group 3	40,788	–	–	7,958,275	44,191,838	1,906,746	–	–	–	7,958,275	1,906,746
23	Load Group 3 (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
	Load Group 3A	34,529	–	–	10,454,688	56,750,273	3,227,562	(70)	–	–	10,454,688	3,227,562
	Load Group 3A (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
	Load Group 4	27,441	–	–	19,489,145	109,094,754	5,350,073	49,321	–	–	19,489,145	5,350,073
	Load Group 4 (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
	Load Group 5	2,196	–	–	6,880,800	47,810,946	2,077,776	8,167	–	–	6,880,800	2,077,776
	Load Group 5 (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
	Street Lighting	732	–	–	–	–	–	–	732	–	–	–
	DUML, excl Street Lighting	–	–	4,030	–	–	–	–	–	4,030	–	–
24	Distributed Generation (Large)											
26	Standard consumer totals	20,777,069	–	427,145,553	120,776,991	257,847,811	23,300,146	57,418	102,762	427,145,553	120,776,535	23,300,146
27	Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–	–
28	Total for all consumers	20,777,069	–	427,145,553	120,776,991	257,847,811	23,300,146	57,418	102,762	427,145,553	120,776,535	23,300,146

Billed quantities by price component *Not Required before DY2025*

sch ref	Standardised price component	[Select one]		[Select one]		[Select one]		[Select one]	
	EDB defined price component								
13		Distribution billed quantity	Transmission billed quantity	Distribution billed quantity	Transmission billed quantity	Distribution billed quantity	Transmission billed quantity	Distribution billed quantity	Transmission billed quantity
15	Residential								
16	Load Group 0								
17	Load Group 0A								
18	Load Group 1A								
19	Load Group 1								
20	Load Group 2								
21	Load Group 2 (Non-standard)								
22	Load Group 3								
23	Load Group 3 (Non-standard)								
	Load Group 3A								
	Load Group 3A (Non-standard)								
	Load Group 4								
	Load Group 4 (Non-standard)								
	Load Group 5								
	Load Group 5 (Non-standard)								
	Street Lighting								
	DUML, excl Street Lighting								
24	Distributed Generation (Large)								
26	Standard consumer totals	–	–	–	–	–	–	–	–
27	Non-standard consumer totals	–	–	–	–	–	–	–	–
28	Total for all consumers	–	–	–	–	–	–	–	–

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

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

sch ref	Consumer group name or price category code	Standardised connection types	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Total distribution line charge revenue	Total transmission line charge revenue
37					*Not Required after DY2024*	*Not Required after DY2024*
38	Residential	Residential	Standard	$46,672	32,212	14,460
39	Load Group 0	General	Standard	$27	20	7
40	Load Group 0A	General	Standard	$97	72	24
41	Load Group 1A	General	Standard	$210	151	59
42	Load Group 1	General	Standard	$2,975	2,075	900
43	Load Group 2	General	Standard	$11,888	8,000	3,888
44	Load Group 2	General	Non-standard	–	–	–
45	Load Group 3	General	Standard	$2,534	1,760	773
	Load Group 3	General	Non-standard	–	–	–
	Load Group 3A	General	Standard	$3,786	2,323	1,463
	Load Group 3A	General	Non-standard	–	–	–
	Load Group 4	General	Standard	$5,510	3,374	2,136
	Load Group 4	General	Non-standard	–	–	–
	Load Group 5	General	Standard	$1,649	851	798
	Load Group 5	General	Non-standard	–	–	–
	Street Lighting	General	Standard	$565	435	130
46	DUML, excl Street Lighting	General	Standard	$0	0	0
47	Distributed Generation (Large)	General	Non-standard	$146	146	–
48	*Add extra rows for additional consumer groups or price category codes as necessary*					
49			**Standard consumer totals**	$75,913	$51,273	$24,640
50			**Non-standard consumer totals**	$146	$146	–
51			**Total for all consumers**	$76,059	$51,419	$24,640
53					**Check**	**OK**

Line charge revenues ($000) by price component *Not Required after DY2024*

sch ref	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)
36	Rate (eg, $ per day, $ per kWh, etc.)	$ / annum	$ / Lamp	$ / kWh	$ / kVA	$ / kVA x km	$ / kW	$ / kVA	$ / annum	$ / kWh	$ / kVA	$ / kW
38	Residential	$0	–	$32,212	–	–	–	–	$8,140	$6,320	–	–
39	Load Group 0	$20	–	–	–	–	–	–	$7	–	–	–
40	Load Group 0A	$72	–	–	–	–	–	–	$24	–	–	–
41	Load Group 1A	$9	–	–	$55	–	$87	–	–	–	$34	$25
42	Load Group 1	$62	–	–	$434	–	$1,579	–	–	–	$454	$446
43	Load Group 2	$140	–	–	$2,160	–	$5,701	–	–	–	$2,421	$1,467
44	Load Group 2 (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
45	Load Group 3	$76	–	–	$557	$71	$1,059	($2)	–	–	$488	$286
	Load Group 3 (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
	Load Group 3A	$64	–	–	$331	$91	$1,837	($1)	–	–	$903	$560
	Load Group 3A (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
	Load Group 4	$141	–	–	$113	$175	$2,528	$418	–	–	$1,321	$815
	Load Group 4 (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
	Load Group 5	$11	–	–	$40	$76	$651	$73	–	–	$500	$298
	Load Group 5 (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
	Street Lighting	$435	–	–	–	–	–	–	$130	–	–	–
46	DUML, excl Street Lighting	$0	–	$0	–	–	–	–	–	$0	–	–
47	Distributed Generation (Large)	$146	–	–	–	–	–	–	–	–	–	–
49	Standard consumer totals	$1,030	–	$32,212	$3,690	$413	$13,442	$487	$8,302	$6,320	$6,121	$3,896
50	Non-standard consumer totals	$146	–	–	–	–	–	–	–	–	–	–
51	Total for all consumers	$1,176	–	$32,212	$3,690	$413	$13,442	$487	$8,302	$6,320	$6,121	$3,896

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

sch ref	Consumer group name or price category code	Total distribution line charge revenue	Total transmission line charge revenue
38	Residential	–	–
39	Load Group 0	–	–
40	Load Group 0A	–	–
41	Load Group 1A	–	–
42	Load Group 1	–	–
43	Load Group 2	–	–
44	Load Group 2 (Non-standard)	–	–
45	Load Group 3	–	–
	Load Group 3 (Non-standard)		
	Load Group 3A		
	Load Group 3A (Non-standard)		
	Load Group 4		
	Load Group 4 (Non-standard)		
	Load Group 5		
	Load Group 5 (Non-standard)		
	Street Lighting		
46	DUML, excl Street Lighting	–	–
47	Distributed Generation (Large)	–	–
49	Standard consumer totals	–	–
50	Non-standard consumer totals	–	–
51	Total for all consumers	–	–
53	**Check**		**Error**

Line charge revenues ($000) by price component *Not Required before DY2025*

sch ref	Standardised price component	[Select one]			[Select one]			[Select one]			[Select one]		
	EDB defined price component												
36		Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)
38	Residential			–			–			–			–
39	Load Group 0			–			–			–			–
40	Load Group 0A			–			–			–			–
41	Load Group 1A			–			–			–			–
42	Load Group 1			–			–			–			–
43	Load Group 2			–			–			–			–
44	Load Group 2 (Non-standard)			–			–			–			–
45	Load Group 3			–			–			–			–
	Load Group 3 (Non-standard)			–			–			–			–
	Load Group 3A			–			–			–			–
	Load Group 3A (Non-standard)			–			–			–			–
	Load Group 4			–			–			–			–
	Load Group 4 (Non-standard)			–			–			–			–
	Load Group 5			–			–			–			–
	Load Group 5 (Non-standard)			–			–			–			–
	Street Lighting			–			–			–			–
46	DUML, excl Street Lighting			–			–			–			–
47	Distributed Generation (Large)			–			–			–			–
49	Standard consumer totals	–	–	–	–	–	–	–	–	–	–	–	–
50	Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–	–	–
51	Total for all consumers	–	–	–	–	–	–	–	–	–	–	–	–

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

53 ### 8(iii): Number of ICPs directly billed

54 Number of directly billed ICPs at year end: 1

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**
Network / Sub-Network Name	**entral Otago & Wanaka Sub-networ**

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.
EDBs should feel free to adjust the page break of this schedule to assist with readibility if needed.

sch ref

8(i): Billed Quantities by Price Component

Consumer group name or price category code	Standardised connection types	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)
Residential	Residential	Standard	18,487	134,764
Load Group 0	General	Standard	109	25
Load Group 0A	General	Standard	334	834
Load Group 1A	General	Standard	338	1,222
Load Group 1	General	Standard	1,801	13,259
Load Group 2	General	Standard	2,185	83,475
Load Group 2	General	Non-standard	0	–
Load Group 3	General	Standard	92	18,317
Load Group 3	General	Non-standard	0	–
Load Group 3A	General	Standard	63	24,388
Load Group 3A	General	Non-standard	0	–
Load Group 4	General	Standard	44	44,158
Load Group 4	General	Non-standard	–	–
Load Group 5	General	Standard	1	7,993
Load Group 5	General	Non-standard	–	–
Street Lighting	General	Standard	7	936
DUML, excl Street Lighting	General	Standard	–	–
Distributed Generation (Large)	General	Non-standard	9	
Add extra rows for additional consumer groups or price category codes as necessary				
		Standard consumer totals	23,460	329,373
		Non-standard consumer totals	9	–
		Total for all consumers	23,469	329,373

Billed quantities by price component *Not Required after DY2024*

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.)	Days	Lamp	kWh	kVA	kVA x km	kW	kVA	Days	kWh	kVA	kW
Residential (Standard)	6,766,212	–	134,764,284	–	–	–	–	–	134,764,284	–	–
Load Group 0 (Standard)	39,846	–	–	–	–	–	–	39,846	–	–	–
Load Group 0A (Standard)	122,130	–	–	–	–	–	–	–	–	–	–
Load Group 1A (Standard)	123,734	–	–	989,872	–	121,186	–	–	–	989,872	121,186
Load Group 1 (Standard)	659,052	–	–	9,885,780	–	1,448,785	–	–	–	9,885,780	1,448,785
Load Group 2 (Standard)	799,657	–	–	40,429,319	–	4,337,563	(385)	–	–	40,429,319	4,337,563
Load Group 2 (Non-standard)	33	–	–	–	–	–	–	–	–	–	–
Load Group 3 (Standard)	33,518	–	–	6,247,004	196,340,341	701,819	(98)	–	–	6,247,004	701,819
Load Group 3 (Non-standard)	24	–	–	–	–	–	–	–	–	–	–
Load Group 3A (Standard)	22,938	–	–	6,729,404	200,599,410	1,075,048	(194)	–	–	6,729,404	1,075,048
Load Group 3A (Non-standard)	24	–	–	–	–	–	–	–	–	–	–
Load Group 4 (Standard)	16,270	–	–	11,160,500	418,862,650	1,885,455	23,646	–	–	11,160,500	1,885,455
Load Group 4 (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
Load Group 5 (Standard)	387	–	–	969,096	62,587,843	50,562	–	–	–	969,096	50,562
Load Group 5 (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
Street Lighting (Standard)	–	1,685,209	936,161	–	–	–	–	–	936,161	–	–
DUML, excl Street Lighting (Standard)	–	–	–	–	–	–	–	–	–	–	–
Distributed Generation (Large) (Non-standard)											
Standard consumer totals	8,583,744	1,685,209	135,700,445	76,410,975	878,390,244	9,620,418	22,968	39,846	135,700,445	76,410,975	9,620,418
Non-standard consumer totals	81	–	–	–	–	–	–	–	–	–	–
Total for all consumers	8,583,825	1,685,209	135,700,445	76,410,975	878,390,244	9,620,418	22,968	39,846	135,700,445	76,410,975	9,620,418

Billed quantities by price component *Not Required before DY2025*

Standardised price component	[Select one]		[Select one]		[Select one]		[Select one]	
EDB defined price component								
	Distribution billed quantity	**Transmission billed quantity**	**Distribution billed quantity**	**Transmission billed quantity**	**Distribution billed quantity**	**Transmission billed quantity**	**Distribution billed quantity**	**Transmission billed quantity**
Residential (Standard)								
Load Group 0 (Standard)								
Load Group 0A (Standard)								
Load Group 1A (Standard)								
Load Group 1 (Standard)								
Load Group 2 (Standard)								
Load Group 2 (Non-standard)								
Load Group 3 (Standard)								
Load Group 3 (Non-standard)								
Load Group 3A (Standard)								
Load Group 3A (Non-standard)								
Load Group 4 (Standard)								
Load Group 4 (Non-standard)								
Load Group 5 (Standard)								
Load Group 5 (Non-standard)								
Street Lighting (Standard)								
DUML, excl Street Lighting (Standard)								
Distributed Generation (Large) (Non-standard)								
Standard consumer totals	–	–	–	–	–	–	–	–
Non-standard consumer totals	–	–	–	–	–	–	–	–
Total for all consumers	–	–	–	–	–	–	–	–

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

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

Consumer group name or price category code	Standardised connection types	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Total distribution line charge revenue *Not Required after DY2024*	Total transmission line charge revenue *Not Required after DY2024*
Residential	Residential	Standard	$25,205	18,074	7,132
Load Group 0	General	Standard	$67	21	45
Load Group 0A	General	Standard	$409	124	285
Load Group 1A	General	Standard	$158	143	15
Load Group 1	General	Standard	$1,568	1,553	15
Load Group 2	General	Standard	$6,580	4,473	2,107
Load Group 2	General	Non-standard	–	–	–
Load Group 3	General	Standard	$1,710	1,056	654
Load Group 3	General	Non-standard	–	–	–
Load Group 3A	General	Standard	$1,559	1,335	223
Load Group 3A	General	Non-standard	–	–	–
Load Group 4	General	Standard	$3,840	2,878	962
Load Group 4	General	Non-standard	–	–	–
Load Group 5	General	Standard	$187	141	47
Load Group 5	General	Non-standard	–	–	–
Street Lighting	General	Standard	$128	87	41
DUML, excl Street Lighting	General	Standard	–	–	–
Distributed Generation (Large)	General	Non-standard	$526	526	–
Add extra rows for additional consumer groups or price category codes as necessary					
		Standard consumer totals	$41,411	$29,885	$11,527
		Non-standard consumer totals	$526	$526	–
		Total for all consumers	$41,938	$30,411	$11,527

Check OK

Line charge revenues ($000) by price component *Not Required after DY2024*

Price component	Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Period Demand (Distribution)	Transformer Lease, Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Transmission)
Rate (eg, $ per day, $ per kWh, etc.)	$ / annum	$ / Lamp	$ / kWh	$ / kVA	$ / kVA x km	$ / kW	$ / kVA	$ / annum	$ / kWh	$ / kVA	$ / kW
Residential (Standard)	($0)	–	$18,074	–	–	–	–	$3,034	$4,098	–	–
Load Group 0 (Standard)	$21	–	–	–	–	–	–	$45	–	–	–
Load Group 0A (Standard)	$124	–	–	–	–	–	–	$285	–	–	–
Load Group 1A (Standard)	$6	–	–	$49	–	$88	–	–	–	$10	$5
Load Group 1 (Standard)	$30	–	–	$369	–	$1,154	($0)	–	–	$12	$3
Load Group 2 (Standard)	$74	–	–	$2,063	–	$2,341	($5)	–	–	$1,330	$777
Load Group 2 (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
Load Group 3 (Standard)	$53	–	–	$246	$216	$542	($1)	–	–	$442	$212
Load Group 3 (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
Load Group 3A (Standard)	$36	–	–	$53	$221	$1,028	($3)	–	–	$137	$87
Load Group 3A (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
Load Group 4 (Standard)	$157	–	–	$780	$458	$1,266	$216	–	–	$582	$380
Load Group 4 (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
Load Group 5 (Standard)	$2	–	–	$34	$69	$35	$1	–	–	$26	$20
Load Group 5 (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
Street Lighting (Standard)	–	$49	$37	–	–	–	–	–	$41	–	–
DUML, excl Street Lighting (Standard)											
Distributed Generation (Large) (Non-standard)	$526	–	–	–	–	–	–	–	–	–	–
Standard consumer totals	$503	$49	$18,111	$3,594	$963	$6,455	$209	$3,364	$4,139	$2,539	$1,485
Non-standard consumer totals	$526	–	–	–	–	–	–	–	–	–	–
Total for all consumers	$1,030	$49	$18,111	$3,594	$963	$6,455	$209	$3,364	$4,139	$2,539	$1,485

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

	Total distribution line charge revenue	Total transmission line charge revenue
Residential (Standard)	–	–
Load Group 0 (Standard)	–	–
Load Group 0A (Standard)	–	–
Load Group 1A (Standard)	–	–
Load Group 1 (Standard)	–	–
Load Group 2 (Standard)	–	–
Load Group 2 (Non-standard)	–	–
Load Group 3 (Standard)	–	–
Load Group 3 (Non-standard)	–	–
Load Group 3A (Standard)	–	–
Load Group 3A (Non-standard)	–	–
Load Group 4 (Standard)	–	–
Load Group 4 (Non-standard)	–	–
Load Group 5 (Standard)	–	–
Load Group 5 (Non-standard)	–	–
Street Lighting (Standard)	–	–
DUML, excl Street Lighting (Standard)	–	–
Distributed Generation (Large) (Non-standard)	–	–
Standard consumer totals	–	–
Non-standard consumer totals	–	–
Total for all consumers	–	–

Not Required before DY20

Check Error

Line charge revenues ($000) by price component *Not Required before DY2025*

Standardised price component	[Select one]			[Select one]			[Select one]			[Select one]		
EDB defined price component												
	Distribution line charge revenue	**Transmission line charge revenue**	**Total line charge revenue (distribution and transmission)**	**Distribution line charge revenue**	**Transmission line charge revenue**	**Total line charge revenue (distribution and transmission)**	**Distribution line charge revenue**	**Transmission line charge revenue**	**Total line charge revenue (distribution and transmission)**	**Distribution line charge revenue**	**Transmission line charge revenue**	**Total line charge revenue (distribution and transmission)**
Residential (Standard)			–			–			–			–
Load Group 0 (Standard)			–			–			–			–
Load Group 0A (Standard)			–			–			–			–
Load Group 1A (Standard)			–			–			–			–
Load Group 1 (Standard)			–			–			–			–
Load Group 2 (Standard)			–			–			–			–
Load Group 2 (Non-standard)			–			–			–			–
Load Group 3 (Standard)			–			–			–			–
Load Group 3 (Non-standard)			–			–			–			–
Load Group 3A (Standard)			–			–			–			–
Load Group 3A (Non-standard)			–			–			–			–
Load Group 4 (Standard)			–			–			–			–
Load Group 4 (Non-standard)			–			–			–			–
Load Group 5 (Standard)			–			–			–			–
Load Group 5 (Non-standard)			–			–			–			–
Street Lighting (Standard)			–			–			–			–
DUML, excl Street Lighting (Standard)			–			–			–			–
Distributed Generation (Large) (Non-standard)			–			–			–			–
Standard consumer totals	–	–	–	–	–	–	–	–	–	–	–	–
Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–	–	–
Total for all consumers	–	–	–	–	–	–	–	–	–	–	–	–

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

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end 4

Company Name	Aurora Energy Limited
For Year Ended	31 March 2024
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.
EDBs should feel free to adjust the page break of this schedule to assist with readibility if needed.

sch ref

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

sch ref	Consumer group name or price category code	Standardised connection types	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	11,409	113,970
16	Load Group 0	General	Standard	108	55
17	Load Group 0A	General	Standard	206	718
18	Load Group 1A	General	Standard	187	560
19	Load Group 1	General	Standard	1,059	9,738
20	Load Group 2	General	Standard	1,916	71,163
21	Load Group 2	General	Non-standard	–	–
22	Load Group 3	General	Standard	39	10,606
23	Load Group 3	General	Non-standard	–	–
	Load Group 3A	General	Standard	37	13,677
	Load Group 3A	General	Non-standard	–	–
	Load Group 4	General	Standard	34	46,753
	Load Group 4	General	Non-standard	1	4,359
	Load Group 5	General	Standard	1	3,420
	Load Group 5	General	Non-standard	1	5,576
	Street Lighting	General	Standard	3	728
	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	14,999	271,387
27			Non-standard consumer totals	4	9,935
28			Total for all consumers	15,003	281,322

Billed quantities by price component *Not Required after DY2024*

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.)	Days	Lamp	kWh	kVA	kVA x km	kW	kVA	Days	kWh	kVA	kW
Residential (Standard)	4,175,579	–	113,969,580	–	–	–	–	–	113,969,580	–	–
Load Group 0 (Standard)	39,681	–	–	–	–	–	–	39,681	–	–	–
Load Group 0A (Standard)	75,220	–	–	–	–	–	–	–	–	–	–
Load Group 1A (Standard)	68,564	–	–	547,016	–	67,798	–	–	–	547,016	67,798
Load Group 1 (Standard)	387,423	–	–	5,795,460	–	1,121,788	–	–	–	5,795,460	1,121,788
Load Group 2 (Standard)	701,350	–	–	31,924,467	–	4,803,319	(126)	–	–	31,924,467	4,803,319
Load Group 2 (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
Load Group 3 (Standard)	14,185	–	–	2,696,138	33,187,687	717,987	–	–	–	2,696,138	717,987
Load Group 3 (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
Load Group 3A (Standard)	13,685	–	–	4,045,653	50,317,445	930,263	–	–	–	4,045,653	930,263
Load Group 3A (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
Load Group 4 (Standard)	12,489	–	–	8,609,000	83,102,716	2,545,592	23,125	–	–	8,609,000	2,545,592
Load Group 4 (Non-standard)	367	–	–	–	–	–	–	367	–	–	–
Load Group 5 (Standard)	367	–	–	915,000	1,098,000	176,958	–	–	–	915,000	176,958
Load Group 5 (Non-standard)	367	–	–	–	–	–	–	367	–	–	–
Street Lighting (Standard)	–	1,188,569	728,072	–	–	–	–	–	728,072	–	–
DUML, excl Street Lighting (Standard)	–	–	–	–	–	–	–	–	–	–	–
Distributed Generation (Large) (Non-standard)											
Standard consumer totals	5,488,543	1,188,569	114,697,652	54,532,734	167,705,848	10,363,705	22,999	39,681	114,697,652	54,532,734	10,363,705
Non-standard consumer totals	734	–	–	–	–	–	–	734	–	–	–
Total for all consumers	5,489,277	1,188,569	114,697,652	54,532,734	167,705,848	10,363,705	22,999	40,415	114,697,652	54,532,734	10,363,705

Billed quantities by price component *Not Required before DY2025*

Standardised price component	[Select one]		[Select one]		[Select one]		[Select one]	
EDB defined price component								
	Distribution billed quantity	Transmission billed quantity	Distribution billed quantity	Transmission billed quantity	Distribution billed quantity	Transmission billed quantity	Distribution billed quantity	Transmission billed quantity
Standard consumer totals	–	–	–	–	–	–	–	–
Non-standard consumer totals	–	–	–	–	–	–	–	–
Total for all consumers	–	–	–	–	–	–	–	–

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

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

sch ref	Consumer group name or price category code	Standardised connection types	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Total distribution line charge revenue *Not Required after DY2024*	Total transmission line charge revenue *Not Required after DY2024*
38	Residential	Residential	Standard	$13,951	9,451	4,500
39	Load Group 0	General	Standard	$36	16	20
40	Load Group 0A	General	Standard	$134	55	78
41	Load Group 1A	General	Standard	$74	50	23
42	Load Group 1	General	Standard	$1,099	609	491
43	Load Group 2	General	Standard	$5,381	3,390	1,990
44	Load Group 2	General	Non-standard	–	–	–
45	Load Group 3	General	Standard	$940	745	194
	Load Group 3	General	Non-standard	–	–	–
	Load Group 3A	General	Standard	$1,254	1,012	242
	Load Group 3A	General	Non-standard	–	–	–
	Load Group 4	General	Standard	$2,344	1,293	1,051
	Load Group 4	General	Non-standard	$137	84	53
	Load Group 5	General	Standard	$110	60	50
	Load Group 5	General	Non-standard	$210	98	111
	Street Lighting	General	Standard	$80	51	29
46	DUML, excl Street Lighting	General	Standard	–	–	–
47	Distributed Generation (Large)	General	Non-standard	$31	31	–
48	*Add extra rows for additional consumer groups or price category codes as necessary*					
49			Standard consumer totals	$25,402	$16,732	$8,670
50			Non-standard consumer totals	$378	$214	$164
51			Total for all consumers	$25,780	$16,946	$8,834
					Check	OK

Line charge revenues ($000) by price component *Not Required after DY2024*

Price component	Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Period Demand (Distribution)	Transformer Lease, Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Transmission)
Rate (eg, $ per day, $ per kWh, etc.)	$ / annum	$ / Lamp	$ / kWh	$ / kVA	$ / kVA x km	$ / kW	$ / kVA	$ / annum	$ / kWh	$ / kVA	$ / kW
Residential (Standard)	$0	–	$9,450	–	–	–	–	$1,861	$2,640	–	–
Load Group 0 (Standard)	$16	–	–	–	–	–	–	$20	–	–	–
Load Group 0A (Standard)	$55	–	–	–	–	–	–	$78	–	–	–
Load Group 1A (Standard)	$3	–	–	$20	–	$28	–	–	–	$11	$12
Load Group 1 (Standard)	$18	–	–	$110	–	$481	–	–	–	$227	$264
Load Group 2 (Standard)	$49	–	–	$1,135	–	$2,207	($2)	–	–	$940	$1,051
Load Group 2 (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
Load Group 3 (Standard)	$20	–	–	$355	$36	$335	–	–	–	$194	$1
Load Group 3 (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
Load Group 3A (Standard)	$19	–	–	$488	$55	$451	–	–	–	$240	$2
Load Group 3A (Non-standard)	–	–	–	–	–	–	–	–	–	–	–
Load Group 4 (Standard)	$47	–	–	$266	$90	$696	$194	–	–	$532	$518
Load Group 4 (Non-standard)	$84	–	–	–	–	–	–	$53	–	–	–
Load Group 5 (Standard)	$1	–	–	$8	$1	$28	$21	–	–	$7	$43
Load Group 5 (Non-standard)	$98	–	–	–	–	–	–	$111	–	–	–
Street Lighting (Standard)	–	$42	$9	–	–	–	–	–	$29	–	–
DUML, excl Street Lighting (Standard)											
Distributed Generation (Large) (Non-standard)	$31	–	–	–	–	–	–	–	–	–	–
Standard consumer totals	$229	$42	$9,460	$2,381	$182	$4,225	$214	$1,959	$2,669	$2,150	$1,891
Non-standard consumer totals	$214	–	–	–	–	–	–	$164	–	–	–
Total for all consumers	$443	$42	$9,460	$2,381	$182	$4,225	$214	$2,123	$2,669	$2,150	$1,891

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

Not Required before DY2025

	Total distribution line charge revenue	Total transmission line charge revenue
Residential (Standard)	–	–
Load Group 0 (Standard)	–	–
Load Group 0A (Standard)	–	–
Load Group 1A (Standard)	–	–
Load Group 1 (Standard)	–	–
Load Group 2 (Standard)	–	–
Load Group 2 (Non-standard)	–	–
Load Group 3 (Standard)	–	–
Load Group 3 (Non-standard)		
Load Group 3A (Standard)		
Load Group 3A (Non-standard)		
Load Group 4 (Standard)		
Load Group 4 (Non-standard)		
Load Group 5 (Standard)		
Load Group 5 (Non-standard)		
Street Lighting (Standard)		
DUML, excl Street Lighting (Standard)	–	–
Distributed Generation (Large) (Non-standard)	–	–
Standard consumer totals	–	–
Non-standard consumer totals	–	–
Total for all consumers	–	–
Check		Error

Line charge revenues ($000) by price component *Not Required before DY2025*

Standardised price component	[Select one]			[Select one]			[Select one]			[Select one]		
EDB defined price component												
	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)
Residential (Standard)			–			–			–			–
Load Group 0 (Standard)			–			–			–			–
Load Group 0A (Standard)			–			–			–			–
Load Group 1A (Standard)			–			–			–			–
Load Group 1 (Standard)			–			–			–			–
Load Group 2 (Standard)			–			–			–			–
Load Group 2 (Non-standard)			–			–			–			–
Load Group 3 (Standard)			–			–			–			–
DUML, excl Street Lighting (Standard)			–			–			–			–
Distributed Generation (Large) (Non-standard)			–			–			–			–
Standard consumer totals	–	–	–	–	–	–	–	–	–	–	–	–
Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–	–	–
Total for all consumers	–	–	–	–	–	–	–	–	–	–	–	–

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

53 **8(iii): Number of ICPs directly billed**

54 Number of directly billed ICPs at year end: 3

Company Name	Aurora Energy Limited
For Year Ended	31 March 2024
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

9a: Asset Register

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.	30,590	31,635	1,045	4
10	All	Overhead Line	Wood poles	No.	23,065	22,043	(1,022)	4
11	All	Overhead Line	Other pole types	No.			–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	522	522	(1)	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km			–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	36	46	10	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.	36	36	–	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	15	1	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.			–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	153	264	111	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.	57	58	1	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	334	335	1	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	24	24	–	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	68	69	1	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2,276	2,278	2	4
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km			–	N/A
37	HV	Distribution Line	SWER conductor	km	9	5	(4)	4
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	778	804	26	3
39	HV	Distribution Cable	Distribution UG PILC	km	413	410	(3)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	5	5	0	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	58	61	3	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	6	3	(3)	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	7,250	7,333	83	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	480	445	(35)	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	933	986	53	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	3,991	4,005	14	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	3,312	3,370	58	4
48	HV	Distribution Transformer	Voltage regulators	No.	32	38	6	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	345	335	(10)	4
50	LV	LV Line	LV OH Conductor	km	1,028	1,025	(3)	4
51	LV	LV Cable	LV UG Cable	km	1,136	1,164	29	4
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	1,071	1,078	7	4
53	LV	Connections	OH/UG consumer service connections	No.	96,311	97,123	812	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	751	729	(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	15	10	(5)	4
58	All	Load Control	Relays	No	2,291	2,305	14	2
59	All	Civils	Cable Tunnels	km			–	N/A

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**
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

9a: Asset Register

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.	18,501	18,817	316	4
10	All	Overhead Line	Wood poles	No.	10,676	10,364	(312)	4
11	All	Overhead Line	Other pole types	No.			–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	144	143	(1)	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km			–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	14	15	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.	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.	82	103	21	4
29	HV	Zone substation switchgear	33kV RMU	No.			–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	3	3	–	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	19	19	–	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	244	244	–	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	1	1	–	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	34	34	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	721	724	3	4
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km			–	N/A
37	HV	Distribution Line	SWER conductor	km	9	5	(4)	4
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	54	57	3	3
39	HV	Distribution Cable	Distribution UG PILC	km	273	271	(2)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	5	5	0	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	3	(3)	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	2,868	2,873	5	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	272	243	(29)	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	413	424	11	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	1,674	1,670	(4)	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	993	1,005	12	4
48	HV	Distribution Transformer	Voltage regulators	No.	2	2	–	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	345	335	(10)	4
50	LV	LV Line	LV OH Conductor	km	809	807	(2)	4
51	LV	LV Cable	LV UG Cable	km	310	318	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.	57,511	57,797	286	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	542	509	(33)	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	12	7	(5)	4
58	All	Load Control	Relays	No	1,122	1,123	1	2
59	All	Civils	Cable Tunnels	km			–	N/A

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**
Network / Sub-network Name	**Central Otago & 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

9a: Asset Register

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.	10,217	10,855	638	4
10	All	Overhead Line	Wood poles	No.	9,583	8,992	(591)	4
11	All	Overhead Line	Other pole types	No.			–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	309	309	0	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km			–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	9	9	(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	–	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.	10	10	–	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	15	1	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.			–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	52	104	52	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.	26	26	–	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	50	51	1	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	13	13	–	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	20	21	1	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1,271	1,273	2	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	515	531	16	3
39	HV	Distribution Cable	Distribution UG PILC	km	58	58	(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.	30	28	(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.	3,396	3,448	52	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	88	85	(3)	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	266	293	27	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	1,860	1,868	8	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	1,476	1,511	35	4
48	HV	Distribution Transformer	Voltage regulators	No.	22	28	6	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.			–	N/A
50	LV	LV Line	LV OH Conductor	km	174	174	(0)	4
51	LV	LV Cable	LV UG Cable	km	510	525	15	4
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	248	252	3	4
53	LV	Connections	OH/UG consumer service connections	No.	23,580	23,986	406	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	131	138	7	4
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot			–	N/A
56	All	Capacitor Banks	Capacitors including controls	No			–	N/A
57	All	Load Control	Centralised plant	Lot	2	2	–	4
58	All	Load Control	Relays	No	698	710	12	2
59	All	Civils	Cable Tunnels	km			–	N/A

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**
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

9a: Asset Register

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)
9	All	Overhead Line	Concrete poles / steel structure	No.	1,872	1,963	91	4
10	All	Overhead Line	Wood poles	No.	2,806	2,687	(119)	4
11	All	Overhead Line	Other pole types	No.			–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	69	69	0	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km			–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	13	22	9	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	57	38	4
29	HV	Zone substation switchgear	33kV RMU	No.			–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	6	6	–	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	12	13	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	284	282	(2)	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	209	216	7	3
39	HV	Distribution Cable	Distribution UG PILC	km	81	81	(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.	13	18	5	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.	986	1,012	26	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	120	117	(3)	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	254	269	15	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	457	467	10	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	843	854	11	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	45	44	(1)	4
51	LV	LV Cable	LV UG Cable	km	315	321	6	4
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	141	143	2	4
53	LV	Connections	OH/UG consumer service connections	No.	15,220	15,340	120	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	78	82	4	4
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	–		–	N/A
56	All	Capacitor Banks	Capacitors including controls	No	–		–	N/A
57	All	Load Control	Centralised plant	Lot	1	1	–	4
58	All	Load Control	Relays	No	471	472	1	2
59	All	Civils	Cable Tunnels	km			–	N/A

Company Name	Aurora Energy Limited
For Year Ended	31 March 2024
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

9b: Asset Age Profile

8 Disclosure Year (year ended)

Number of assets at disclosure year end by installation date

9	Voltage	Asset category	Asset class	Units	pre-1940	1940–1949	1950–1959	1960–1969	1970–1979	1980–1989	1990–1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
10	All	Overhead Line	Concrete poles / steel structure	No.	13	5	1,442	5,917	4,253	2,873	1,622	97	71	119	150	125	61	105	167	161	157
11	All	Overhead Line	Wood poles	No.	767	458	1,203	4,701	3,634	2,935	2,708	286	217	217	354	282	289	230	282	285	268
12	All	Overhead Line	Other pole types	No.																	
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	58	3	61	120	72	36	124	0		1			0		6		1
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km																	
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km					0	1	6					0	1	1	0	0	2
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	2	8	7	4										
25	HV	Zone substation Buildings	Zone substations 110kV+	No.																	
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.																	
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.												3					
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.																	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.			40	15	29	25	22	1			2	3	1			1	17
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.					5	7	10			1	1		2		3	4	1
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.			46	21	62	24	26				11	17		10		8	
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.					3		2	1			4	2		4			
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.			4	9	12	6	6	1		1	3	1	1	1			
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	13	44	150	561	384	349	330	12	11	14	7	10	29	9	12	7	9
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km																	
38	HV	Distribution Line	SWER conductor	km			0	0	0	0											
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km				0	6	10	62	12	23	25	30	54	32	38	51	34	21
40	HV	Distribution Cable	Distribution UG PILC	km	0	8	34	47	69	71	65	6	6	9	13	6	9	11	15	5	8
41	HV	Distribution Cable	Distribution Submarine Cable	km		1															
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.						1	1					2	3		4	6	7
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.					2												
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	4	10	66	417	422	541	941	128	106	120	131	157	125	146	117	131	130
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.				44	38	52	58	7	3	19	19	16	23	17	32	16	27
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.					37	58	111	10	16	18	40	10	26	23	18	20	24
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	1	2	25	193	314	444	843	103	85	96	104	93	76	72	67	72	73
48	HV	Distribution Transformer	Ground Mounted Transformer	No.				33	154	175	425	59	93	93	115	146	172	159	143	117	124
49	HV	Distribution Transformer	Voltage regulators	No.					1										3		4
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.				1	101	93	115	8	2	4	1		2	1	1		
51	LV	LV Line	LV OH Conductor	km	57	34	102	230	210	158	171	5	4	3	4	5	3	3	2	2	2
52	LV	LV Cable	LV UG Cable	km	0		1	22	43	159	157	19	21	25	41	48	51	44	47	40	36
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	15	9	32	139	151	242	287	7	7	8	9	10	10	7	10	11	9
54	LV	Connections	OH/UG consumer service connections	No.	13,058	2,713	6,799	8,605	7,072	4,454	21,654	1,010	952	1,201	1,372	1,563	1,567	1,737	1,520	1,645	1,213
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.			147	46	60	30	48			7	18	25	3	22		2	
56	All	SCADA and communications	SCADA and communications equipment operating as a single syst	Lot																	
57	All	Capacitor Banks	Capacitors including controls	No																	
58	All	Load Control	Centralised plant	Lot				1	3												1
59	All	Load Control	Relays	No		1	2	37	79	103	250	24	43	43	58	101	132	116	112	85	61
60	All	Civils	Cable Tunnels	km																	

9	Asset class	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	No. with age unknown	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
10	Concrete poles / steel structure	112	130	345	535	445	729	646	962	2,246	1,493	1,087	1,298	1,714	1,406	1,149			31,635		4
11	Wood poles	350	342	241	141	91	103	95	133	640	196	140	140	150	95	70			22,043		4
12	Other pole types																		–		N/A
13	Subtransmission OH up to 66kV conductor	6	11		0	0	3	2		1	1	0	1	11	1	1			522		4
14	Subtransmission OH 110kV+ conductor																		–		N/A
15	Subtransmission UG up to 66kV (XLPE)	1	0	0	1	4		1	0	3	10		0	1	2	9			46		3
16	Subtransmission UG up to 66kV (Oil pressurised)																		25		3
17	Subtransmission UG up to 66kV (Gas pressurised)																		16		3
18	Subtransmission UG up to 66kV (PILC)			0															11		3
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	1			1	1	1	1	1	1				1	1			36		4
25	Zone substations 110kV+																		–		N/A
26	50/66/110kV CB (Indoor)																		–		N/A
27	50/66/110kV CB (Outdoor)		1				2	1			7					1			15		4
28	33kV Switch (Ground Mounted)																		–		N/A
29	33kV Switch (Pole Mounted)	2	3	2	1	27	9	10	4	2	19	1	3	13	8	4			264		4
30	33kV RMU												1						1		4
31	22/33kV CB (Indoor)										3								9		4
32	22/33kV CB (Outdoor)	2		3	2	3			1	1			2	5	4	1			58		4
33	3.3/6.6/11/22kV CB (ground mounted)	19	20	12	2	10	6	5			16		2		2	16			335		4
34	3.3/6.6/11/22kV CB (pole mounted)			1				1	1		1		1	2	1				24		4
35	Zone Substation Transformers	2	4	1	2	1	1	2			2	1	3	1	1	3			69		4
36	Distribution OH Open Wire Conductor	13	13	6	8	7	15	22	10	13	11	27	30	78	47	28			2,278		4
37	Distribution OH Aerial Cable Conductor																		–		N/A
38	SWER conductor														4				5		4
39	Distribution UG XLPE or PVC	15	14	9	10	29	40	40	27	30	34	28	40	36	29	26			804		3
40	Distribution UG PILC	9	7	5	3	4	1	1	0	0	0		0	0	0	0			410		3
41	Distribution Submarine Cable													3					5		4
42	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	1	1		2			6	1	3		1	8	5	3	6			61		4
43	3.3/6.6/11/22kV CB (Indoor)		1																3		4
44	3.3/6.6/11/22kV Switches and fuses (pole mounted)	142	141	98	123	116	168	165	127	234	283	285	352	480	534	393			7,333		4
45	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	23	11	12	15	2	2	1	1	2	2	1			1	1			445		3
46	3.3/6.6/11/22kV RMU	16	20	23	13	16	17	33	39	29	55	59	65	63	62	65			986		3
47	Pole Mounted Transformer	56	54	53	77	61	81	64	40	86	90	111	146	147	163	113			4,005		4
48	Ground Mounted Transformer	55	80	61	64	85	99	103	92	95	112	101	113	98	98	106			3,370		4
49	Voltage regulators	5			3		4						3	2	7	6			38		4
50	Ground Mounted Substation Housing		1			1	1					1			1	1			335		4
51	LV OH Conductor	3	2	1	2	2	2	1	1	1	1	2	2	1	5	5			1,025		4
52	LV UG Cable	22	14	20	15	20	23	28	32	33	41	40	31	34	34	25			1,164		4
53	LV OH/UG Streetlight circuit	9	7	10	7	7	4	12	8	11	9	8	5	4	7	6			1,078		4
54	OH/UG consumer service connections	1,085	993	877	1,015	1,104	1,209	1,247	1,648	1,495	1,520	1,402	1,556	1,336	1,307	1,194			97,123		4
55	Protection relays (electromechanical, solid state and numeric)	43	5	15	6	19	7	10	2	9	41	13	59	29	28	35			729		4
56	SCADA and communications equipment operating as a single syst										1								1		4
57	Capacitors including controls			3															3		4
58	Centralised plant	1	3				1												10		4
59	Relays	30	27	28	16	22	9	502	232	27	26	38	29	17	24	31			2,305		2
60	Cable Tunnels																		–		N/A

Company Name: **Aurora Energy Limited**
For Year Ended: **31 March 2024**
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

9b: Asset Age Profile

8 Disclosure Year (year ended)

Number of assets at disclosure year end by installation date

9	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007
10	All	Overhead Line	Concrete poles / steel structure	No.	1	2	1,363	5,563	2,719	1,941	746	21	11	41	53	23	16	22	29
11	All	Overhead Line	Wood poles	No.	751	454	1,128	2,101	897	1,122	1,469	169	153	115	111	87	112	100	108
12	All	Overhead Line	Other pole types	No.															
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	49		51	27	3		2								
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km															
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km															
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	2	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.			27	14	4		9								
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
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.			46	21	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	7	10	2	2							1	
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	3	13	76	234	124	67	65	5	4	8	3	4	5	5	2
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km															
38	HV	Distribution Line	SWER conductor	km			0	0	0	0									
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km				0	0	0	4	1	1	2	2	2	2	3	3
40	HV	Distribution Cable	Distribution UG PILC	km	0	8	34	47	68	48	29	2	1	1	1	1	2	3	1
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
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.					2										
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	2	10	42	353	292	282	391	15	14	19	27	36	29	52	34
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.				44	38	52	41	5		9	4	6		3	2
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.					37	56	73	8	5	4	8	5	12	5	3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.			2	138	175	223	410	39	27	25	39	27	29	34	26
48	HV	Distribution Transformer	Ground Mounted Transformer	No.				33	139	128	198	16	10	15	21	14	20	36	19
49	HV	Distribution Transformer	Voltage regulators	No.					1										
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.				1	101	93	115	8	2	4	1		2	1	1
51	LV	LV Line	LV OH Conductor	km	52	21	64	167	168	140	148	4	3	2	3	4	3	2	2
52	LV	LV Cable	LV UG Cable	km	0		1	22	42	34	39	4	3	4	5	8	8	13	11
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	14	5	18	114	135	105	218	3	3	2	4	3	4	2	3
54	LV	Connections	OH/UG consumer service connections	No.	13,058	2,713	6,799	8,601	7,064	4,449	4,826	311	283	245	358	485	433	528	505
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.			147	46	54	3	19					22		12	
56	All	SCADA and communications	SCADA and communications equipment operating as a single syst	Lot															
57	All	Capacitor Banks	Capacitors including controls	No															
58	All	Load Control	Centralised plant	Lot				1	3										
59	All	Load Control	Relays	No		1	2	33	61	55	90	6	2	4	4	4	2	3	5
60	All	Civils	Cable Tunnels	km															

9	Asset class	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	No. with age unknown	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
10	Concrete poles / steel structure	19	16	25	27	79	153	168	311	292	530	1,048	885	613	553	608	520	419			18,817		4
11	Wood poles	140	129	89	81	101	62	36	21	19	37	491	106	61	42	20	22	30			10,364		4
12	Other pole types																				–		N/A
13	Subtransmission OH up to 66kV conductor															11					143		4
14	Subtransmission OH 110kV+ conductor																				–		N/A
15	Subtransmission UG up to 66kV (XLPE)	0			0	0		3		0	0	3	6		0	0	1				15		3
16	Subtransmission UG up to 66kV (Oil pressurised)																				25		3
17	Subtransmission UG up to 66kV (Gas pressurised)																				16		3
18	Subtransmission UG up to 66kV (PILC)				0																11		3
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	1					1			21		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)				2	2		27	1		4		2		2	9					103		4
30	33kV RMU																				–		N/A
31	22/33kV CB (Indoor)												3								3		4
32	22/33kV CB (Outdoor)	4				3	2									2					19		4
33	3.3/6.6/11/22kV CB (ground mounted)			11	17								16					15			244		4
34	3.3/6.6/11/22kV CB (pole mounted)															1					1		4
35	Zone Substation Transformers				2		2						2			1		2			34		4
36	Distribution OH Open Wire Conductor	5	5	5	1	1	0	2	2	0	0	1	0	14	9	34	14	12			724		4
37	Distribution OH Aerial Cable Conductor																				–		N/A
38	SWER conductor																4				5		4
39	Distribution UG XLPE or PVC	1	1	0	2	1	1	1	1	2	4	2	2	4	3	5	2	4			57		3
40	Distribution UG PILC	1	3	3	6	3	3	3	1	1	0	0	0		0	0	0				271		3
41	Distribution Submarine Cable															3					5		4
42	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers		3		1					4		1		1	1	1					15		4
43	3.3/6.6/11/22kV CB (Indoor)				1																3		4
44	3.3/6.6/11/22kV Switches and fuses (pole mounted)	24	21	22	21	17	25	35	38	47	43	70	77	137	138	223	180	157			2,873		4
45	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	3	9	1	6	5	10	1				1	1	1				1			243		3
46	3.3/6.6/11/22kV RMU	2	9	6	10	8	9	7	9	8	15	4	12	14	25	27	21	22			424		3
47	Pole Mounted Transformer	20	16	16	13	17	20	15	28	14	19	26	24	39	42	67	53	47			1,670		4
48	Ground Mounted Transformer	11	21	14	20	20	16	19	19	24	24	27	15	32	29	12	23	30			1,005		4
49	Voltage regulators														1						2		4
50	Ground Mounted Substation Housing				1			1	1					1			1	1			335		4
51	LV OH Conductor	1	1	2	2	0	2	1	1	0	1	0	1	1	1	1	3	4			807		4
52	LV UG Cable	7	8	8	4	8	7	8	7	7	8	8	7	8	9	8	7	6			318		4
53	LV OH/UG Streetlight circuit	3	4	6	4	6	4	3	2	5	4	2	1	1	1	1	1	2			683		4
54	OH/UG consumer service connections	538	360	428	369	378	364	378	413	364	443	426	451	424	464	426	469	444			57,797		4
55	Protection relays (electromechanical, solid state and numeric)	2		28	1			14		4	2	2	27	13	46	26	20	21			509		4
56	SCADA and communications equipment operating as a single syst												1								1		4
57	Capacitors including controls					3															3		4
58	Centralised plant				3																7		4
59	Relays	6	7	5	5	14	4	4	4	492	223	13	5	14	20	6	14	15			1,123		2
60	Cable Tunnels																				–		N/A

Company Name	Aurora Energy Limited
For Year Ended	31 March 2024
Network / Sub-network Name	Central Otago & 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

9b: Asset Age Profile

8 Disclosure Year (year ended)

Number of assets at disclosure year end by installation date

9	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	No. with age unknown	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.	12	3	79	326	1,326	714	685	63	45	68	79	89	36	70	122	115	127	83	75	214	372	251	374	329	383	998	511	418	667	877	708	636			10,855		4
11	All	Overhead Line	Wood poles	No.	16		74	2,233	2,085	1,249	831	85	41	81	217	152	150	100	146	98	99	215	219	106	50	51	71	68	81	120	61	61	75	98	44	15			8,992		4
12	All	Overhead Line	Other pole types	No.																																			–		N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	9		8	67	57	34	102	0		1					4			6	11			0	2	2		1	1	0	1	0	1	0			309		4
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km																																			–		N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km						1	1					0	0	1	0			1				0		1			3		0	0	0				9		3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km																																			–		N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km																																			–		N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km							0																												0		3
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km																																			–		N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km																																			–		N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km																																			–		N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km																																			–		N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km																																			–		N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.					1	2	1												1			1	1	1	1						1				10		4
25	HV	Zone substation Buildings	Zone substations 110kV+	No.																																			–		N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.																																			–		N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.												3							1				2	1			7					1			15		4
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.																																			–		N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.			13	1		21	11	1			2	3					2		1		1		8	9			16	1	1	2	8	3			104		4
30	HV	Zone substation switchgear	33kV RMU	No.																													1						1		4
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.																																			–		N/A
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.						7	4			1			1				1					3			1				2	2	4				26		4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.						7					11			1		8			3		2	3	6	5					2		2	1			51		4
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.					1		1	1			4	2												1	1				1	1					13		4
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.			1	1	1	2	1			1	3	1							1			1	1	2					3		1	1			21		4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	6	31	68	280	246	192	184	5	5	5	2	6	24	1	6	0	3	6	11	2	8	6	12	22	4	11	10	13	20	43	28	12			1,273		4
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km																																			–		N/A
38	HV	Distribution Line	SWER conductor	km																																			–		N/A
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km				0	5	8	31	7	13	13	20	34	17	22	35	17	15	10	8	7	9	28	34	32	15	23	22	18	28	22	22	17			531		3
40	HV	Distribution Cable	Distribution UG PILC	km	0				0	12	15	2	3	3	3	3	5	2	6	1	0	2	0	1	0	0									0	0			58		3
41	HV	Distribution Cable	Distribution Submarine Cable	km																																			–		N/A
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.						1	1					2	1		1	6	2	1			1			1	1	2			1	3	3	1			28		4
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.																																			–		N/A
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	2	–	24	55	109	203	369	75	57	62	78	90	65	67	57	86	80	89	98	58	83	77	117	101	70	137	172	121	173	209	276	188			3,448		4
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.							7	1		8	5	2	9	1	14	2	11	10	2	6	3		1	1	1		1								85		3
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.						1	15	1	4	8	11	1	9	4	6	5	3	6	6	7	3	6	4	12	8	15	25	29	25	24	26	29			293		3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	1	2	21	46	118	178	314	45	41	51	54	52	37	33	34	43	39	25	35	32	46	43	45	42	18	51	57	63	95	69	88	50			1,868		4
48	HV	Distribution Transformer	Ground Mounted Transformer	No.					8	32	118	18	47	44	55	74	92	70	81	59	67	28	28	28	37	56	73	57	49	55	62	51	58	55	56	53			1,511		4
49	HV	Distribution Transformer	Voltage regulators	No.																	2	5			3		4						2	2	4	6			28		4
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.																																			–		N/A
51	LV	LV Line	LV OH Conductor	km	5	12	29	50	30	17	18	1	1	0	1	1	1	1	1	0	1	1	0	0	0	0	0	0	0	0	0	1	1	0	1	1			174		4
52	LV	LV Cable	LV UG Cable	km					1	71	64	5	8	13	17	22	29	21	17	22	15	11	6	7	5	9	11	16	17	18	27	22	15	20	21	14			525		4
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	1	4	10	20	11	86	34	2	2	5	2	3	4	4	3	7	5	2	2	3	3	3	2	3	3	4	4	6	2	2	4	3			252		4
54	LV	Connections	OH/UG consumer service connections	No.				3	5	4	10,632	340	321	488	568	606	587	590	582	698	541	365	343	279	347	417	506	610	757	697	673	650	649	609	581	538			23,986		4
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.					6	16	3			4	16	3		10				4	4		6		7	6		7	13		13	2	8	10			138		4
56	All	SCADA and communications	SCADA and communications equipment operating as a single syst	Lot																																			–		N/A
57	All	Capacitor Banks	Capacitors including controls	No																																			–		N/A
58	All	Load Control	Centralised plant	Lot																	1						1												2		4
59	All	Load Control	Relays	No				4	12	31	89	7	20	23	29	56	77	66	68	42	37	16	10	8	9	13	5	6	7	7	14	21	3	8	8	14			710		2
60	All	Civils	Cable Tunnels	km																																			–		N/A

Company Name: **Aurora Energy Limited**
For Year Ended: **31 March 2024**
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

9b: Asset Age Profile

8 Disclosure Year (year ended)

Number of assets at disclosure year end by installation date

sch ref	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	No. with age unknown	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
9	Voltage	Asset category	Asset class	Units																																					
10	All	Overhead Line	Concrete poles / steel structure	No.				28	208	218	191	13	15	10	18	13	9	13	16	27	14	4	28	52	10	26	44	25	49	200	97	56	78	229	178	94			1,963		4
11	All	Overhead Line	Wood poles	No.		4	1	367	652	564	408	32	23	21	26	43	27	30	28	47	40	46	42	34	29	4	11	8	15	29	29	18	23	32	29	25			2,687		4
12	All	Overhead Line	Other pole types	No.																																			–		N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km		3	2	26	12	2	19						0		2		1				0		1							0	0	0			69		4
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km																																			–		N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km					0		5						1	0	0	0	2	0		0	1						1			0	0	9			22		3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km																																			–		N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km																																			–		N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km																																			–		N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km																																			–		N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km																																			–		N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km																																			–		N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km																																			–		N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km																																			–		N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.					1	1	2											1																	5		4
25	HV	Zone substation Buildings	Zone substations 110kV+	No.																																			–		N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.																																			–		N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.																																			–		N/A
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.																																			–		N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.					25	4	2						1			1	15	2						1		2	1			2		1			57		4
30	HV	Zone substation switchgear	33kV RMU	No.																																			–		N/A
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.							6																												6		4
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.					1		6						1					2								1				1		1			13		4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.							13											8		12		7													40		4
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.					2		1							4						1							1					1			10		4
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.				1	1	2	3	1					1					2	1	1								1							14		4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	4		6	48	13	90	81	2	2	1	1	0	0	3	4	2	1	3	1	3	0		1	0	5	1	0	0	1	0	5	5			282		4
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km																																			–		N/A
38	HV	Distribution Line	SWER conductor	km																																			–		N/A
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km						2	27	4	9	10	7	18	12	12	14	15	5	4	4	2	1	1	5	6	8	5	11	6	8	9	6	6			216		3
40	HV	Distribution Cable	Distribution UG PILC	km					0	12	21	3	2	5	9	1	2	5	8	3	5	4	0	0	0	0		0	0										81		3
41	HV	Distribution Cable	Distribution Submarine Cable	km																																			–		N/A
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.													2				2				1			1					6	1		5			18		4
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.																																			–		N/A
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	–	–	–	9	21	56	181	38	35	39	26	31	31	27	26	21	29	31	22	23	15	4	13	17	14	27	34	27	41	48	78	48			1,012		4
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.							10	1	3	2	10	8	14	13	16	11	7	12	3	1	2	1	1			1					1				117		3
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.						1	23	1	7	6	21	4	5	14	9	13	12	4	4	8	1	3	4	13	16	10	18	16	15	12	15	14			269		3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.			2	9	21	43	119	19	17	20	11	14	10	5	7	9	18	15	6	4	11	3	8	8	3	9	9	9	9	11	22	16			467		4
48	HV	Distribution Transformer	Ground Mounted Transformer	No.					7	15	109	25	36	34	39	58	60	53	43	47	36	13	32	13	11	10	7	22	19	13	35	18	26	31	19	23			854		4
49	HV	Distribution Transformer	Voltage regulators	No.															3		2														3				8		4
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.																																			–		N/A
51	LV	LV Line	LV OH Conductor	km		1	8	13	12	2	6	0	0	1	0	0	0	0		0	0		0	0	0	0	0	0		0		0			0	0			44		4
52	LV	LV Cable	LV UG Cable	km				0	1	54	53	10	10	8	18	18	13	10	18	11	13	3	5	5	3	3	4	6	6	6	7	11	7	6	7	5			321		4
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	4	5	5	50	34	2	2	1	2	5	2	1	4	1	0	1	1	1	1	0	–	4	1	4	4	1	1	1	3	1			143		4
54	LV	Connections	OH/UG consumer service connections	No.				1	3	1	6,196	359	348	468	446	472	547	619	433	409	312	292	281	220	304	309	290	273	448	372	396	328	443	301	257	212			15,340		4
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.						11	26			3	2		3					11		15		5					1			1		4			82		4
56	All	SCADA and communications	SCADA and communications equipment operating as a single syst	Lot																																			–		N/A
57	All	Capacitor Banks	Capacitors including controls	No																																			–		N/A
58	All	Load Control	Centralised plant	Lot																		1																	1		4
59	All	Load Control	Relays	No					6	17	71	11	21	16	25	41	53	47	39	37	17	9	12	6	3	5		4	2	7	7	3	6	3	2	2			472		2
60	All	Civils	Cable Tunnels	km																																			–		N/A

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**
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 9c: Overhead Lines and Underground Cables

sch ref		Overhead (km)	Underground (km)	Total circuit length (km)
10				
11	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**
12	> 66kV			–
13	50kV & 66kV	127	3	129
14	33kV	395	96	491
15	SWER (all SWER voltages)	5		5
16	22kV (other than SWER)			–
17	6.6kV to 11kV (inclusive—other than SWER)	2,278	1,219	3,497
18	Low voltage (< 1kV)	1,025	1,164	2,190
19	**Total circuit length (for supply)**	3,830	2,481	6,312
20				
21	Dedicated street lighting circuit length (km)	531	547	1,078
22	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			58
23				

sch ref		Circuit length (km)	(% of total overhead length)	
24	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**	
25	Urban	1,154	30%	
26	Rural	2,589	68%	
27	Remote only		–	
28	Rugged only	87	2%	
29	Remote and rugged		–	
30	Unallocated overhead lines		–	
31	**Total overhead length**	3,830	100%	
32				
33		**Circuit length (km)**	**(% of total circuit length)**	
34	Length of circuit within 10km of coastline or geothermal areas (where known)	1,465	23%	
35				
36		**Circuit length (km)**	**(% of total overhead length)**	
37	Overhead circuit requiring vegetation management	3,830	100%	*Not required after DY2025*
38		**Total newly identified throughout the disclosure year**	**Total remaining at high risk at the disclosure year-end**	
39	Number of overhead circuit sites at high risk from vegetation damage		–	*Not required before DY2026*
40				

41 **Breakdown of overhead circuit sites at high risk from vegetation damage at disclosure year-end**

sch ref	Category of overhead circuit site	Number of overhead circuit sites at high risk from vegetation damage at disclosure year-end	Number of overhead circuit sites involving critical assets at disclosure year-end	
42				
43	[Single tree]			*Not required before DY2026*
44	[Single tree - Urban]			*Not required before DY2026*
45	[Single tree - Rural]			*Not required before DY2026*
46	[Row of trees]			*Not required before DY2026*
47	[Span between two poles (X metres)]			*Not required before DY2026*
48	[Other]			*Not required before DY2026*
49	**Total number of sites**	–	–	*Not required before DY2026*

50 ** Insert new rows in table above Total line as necessary*

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**
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 **9c: Overhead Lines and Underground Cables**

10

sch ref	Circuit length by operating voltage (at year end)	Overhead (km)	Underground (km)	Total circuit length (km)	
11	**Circuit length by operating voltage (at year end)**				
12	> 66kV			–	
13	50kV & 66kV			–	
14	33kV	143	67	210	
15	SWER (all SWER voltages)	5		5	
16	22kV (other than SWER)			–	
17	6.6kV to 11kV (inclusive—other than SWER)	724	334	1,058	
18	Low voltage (< 1kV)	807	318	1,125	
19	**Total circuit length (for supply)**	1,679	719	2,398	
20					
21	Dedicated street lighting circuit length (km)	459	224	683	
22	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			4	
23					
24	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**		
25	Urban	964	57%		
26	Rural	706	42%		
27	Remote only		–		
28	Rugged only	9	1%		
29	Remote and rugged		–		
30	Unallocated overhead lines		–		
31	**Total overhead length**	1,679	100%		
32					
33		**Circuit length (km)**	**(% of total circuit length)**		
34	Length of circuit within 10km of coastline or geothermal areas (where known)	1,465	61%		
35					
36		**Circuit length (km)**	**(% of total overhead length)**		
37	Overhead circuit requiring vegetation management	1,679	100%	*Not required after DY2025*	
38		**Total newly identified throughout the disclosure year**	**Total remaining at high risk at the disclosure year-end**		
39	Number of overhead circuit sites at high risk from vegetation damage		–	*Not required before DY2026*	
40					

41 **Breakdown of overhead circuit sites at high risk from vegetation damage at disclosure year-end**

sch ref	Category of overhead circuit site	Number of overhead circuit sites at high risk from vegetation damage at disclosure year-end	Number of overhead circuit sites involving critical assets at disclosure year-end	
42				
43	[Single tree]			*Not required before DY2026*
44	[Single tree - Urban]			*Not required before DY2026*
45	[Single tree - Rural]			*Not required before DY2026*
46	[Row of trees]			*Not required before DY2026*
47	[Span between two poles (X metres)]			*Not required before DY2026*
48	[Other]			*Not required before DY2026*
49	**Total number of sites**	–	–	*Not required before DY2026*

50 ** Insert new rows in table above Total line as necessary*

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**
Network / Sub-network Name	**Central Otago & 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

9c: Overhead Lines and Underground Cables

Circuit length by operating voltage (at year end)	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**
> 66kV			–
50kV & 66kV	127	3	129
33kV	182	7	189
SWER (all SWER voltages)			–
22kV (other than SWER)			–
6.6kV to 11kV (inclusive—other than SWER)	1,273	589	1,862
Low voltage (< 1kV)	174	525	699
Total circuit length (for supply)	1,756	1,123	2,879
Dedicated street lighting circuit length (km)	57	195	252
Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			32

Overhead circuit length by terrain (at year end)	**Circuit length (km)**	**(% of total overhead length)**
Urban	126	7%
Rural	1,575	90%
Remote only		–
Rugged only	55	3%
Remote and rugged		–
Unallocated overhead lines		–
Total overhead length	1,756	100%

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

	Circuit length (km)	**(% of total overhead length)**	
Overhead circuit requiring vegetation management	1,756	100%	*Not required after DY2025*

	Total newly identified throughout the disclosure year	**Total remaining at high risk at the disclosure year-end**	
Number of overhead circuit sites at high risk from vegetation damage		–	*Not required before DY2026*

Breakdown of overhead circuit sites at high risk from vegetation damage at disclosure year-end

Category of overhead circuit site	Number of overhead circuit sites at high risk from vegetation damage at disclosure year-end	Number of overhead circuit sites involving critical assets at disclosure year-end	
[Single tree]			*Not required before DY2026*
[Single tree - Urban]			*Not required before DY2026*
[Single tree - Rural]			*Not required before DY2026*
[Row of trees]			*Not required before DY2026*
[Span between two poles (X metres)]			*Not required before DY2026*
[Other]			*Not required before DY2026*
Total number of sites	–	–	*Not required before DY2026*

** Insert new rows in table above Total line as necessary*

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**
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

9 9c: Overhead Lines and Underground Cables

sch ref		Overhead (km)	Underground (km)	Total circuit length (km)
10				
11	**Circuit length by operating voltage (at year end)**			
12	> 66kV			–
13	50kV & 66kV			–
14	33kV	69	22	91
15	SWER (all SWER voltages)			–
16	22kV (other than SWER)			–
17	6.6kV to 11kV (inclusive—other than SWER)	282	296	578
18	Low voltage (< 1kV)	44	321	365
19	**Total circuit length (for supply)**	395	639	1,034
20				
21	Dedicated street lighting circuit length (km)	15	128	143
22	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			23
23				

sch ref		Circuit length (km)	(% of total overhead length)
24	**Overhead circuit length by terrain (at year end)**		
25	Urban	64	16%
26	Rural	308	78%
27	Remote only		–
28	Rugged only	23	6%
29	Remote and rugged		–
30	Unallocated overhead lines		–
31	**Total overhead length**	395	100%
32			

sch ref		Circuit length (km)	(% of total circuit length)
33			
34	Length of circuit within 10km of coastline or geothermal areas (where known)	–	–
35			

sch ref		Circuit length (km)	(% of total overhead length)	
36				
37	Overhead circuit requiring vegetation management	395	100%	*Not required after DY2025*

sch ref		Total newly identified throughout the disclosure year	Total remaining at high risk at the disclosure year-end	
38				
39	Number of overhead circuit sites at high risk from vegetation damage		–	*Not required before DY2026*
40				

41 **Breakdown of overhead circuit sites at high risk from vegetation damage at disclosure year-end**

sch ref	Category of overhead circuit site	Number of overhead circuit sites at high risk from vegetation damage at disclosure year-end	Number of overhead circuit sites involving critical assets at disclosure year-end	
42				
43	[Single tree]			*Not required before DY2026*
44	[Single tree - Urban]			*Not required before DY2026*
45	[Single tree - Rural]			*Not required before DY2026*
46	[Row of trees]			*Not required before DY2026*
47	[Span between two poles (X metres)]			*Not required before DY2026*
48	[Other]			*Not required before DY2026*
49	**Total number of sites**	–	–	*Not required before DY2026*

50 ** Insert new rows in table above Total line as necessary*

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**

SCHEDULE 9d: REPORT ON EMBEDDED NETWORKS

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

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

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**
Network / Sub-network Name	**Total Network**

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref

8 9e(i): Consumer Connections and Decommissionings

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

sch ref	Consumer types defined by EDB*	Number of connections (ICPs)
11	Residential	901
	Load Group 0	4
	Load Group 0A	28
	Load Group 1A	22
	Load Group 1	28
	Load Group 2	214
	Load Group 3	10
	Load Group 3A	12
12	Load Group 4	4
13	Load Group 5	–
14	Street Lighting	2
15	Distributed Unmetered Load (excl. Street Lighting)	–
16	* include additional rows if needed	
17	**Connections total**	1,225

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

sch ref	Consumer types defined by EDB*	Number of decommissionings
21	Residential	148
	Load Group 0	5
	Load Group 0A	116
	Load Group 1A	9
	Load Group 1	29
	Load Group 2	42
	Load Group 3	–
	Load Group 3A	1
22	Load Group 4	2
23	Load Group 5	–
24	Street Lighting	–
25	Distributed Unmetered Load (excl. Street Lighting)	–
26	* include additional rows if needed	
27	**Decommissionings total**	352

29 Distributed generation

sch ref			
30	Number of connections made in year	660	connections
31	Capacity of distributed generation installed in year	5.35	MVA

33 9e(ii): System Demand

sch ref			Demand at time of maximum coincident demand (MW)
36		**Maximum coincident system demand**	
37		GXP demand	254
38	*plus*	Distributed generation output at HV and above	57
39		**Maximum coincident system demand**	311
40	*less*	Net transfers to (from) other EDBs at HV and above	–
41		**Demand on system for supply to consumers' connection points**	311

sch ref			Energy (GWh)	
42		**Electricity volumes carried**		
43		Electricity supplied from GXPs	1,152	
44	*less*	Electricity exports to GXPs	53	
45	*plus*	Electricity supplied from distributed generation	373	
46	*less*	Net electricity supplied to (from) other EDBs	5	
47		**Electricity entering system for supply to consumers' connection points**	1,467	
48	*less*	Total energy delivered to ICPs	1,424	
49		**Electricity losses (loss ratio)**	43	2.9%
51		**Load factor**	0.54	

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**
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).

52	**9e(iii): Transformer Capacity**	
53		**(MVA)**
54	Distribution transformer capacity (EDB owned)	979
55	Distribution transformer capacity (Non-EDB owned)	67
56	**Total distribution transformer capacity**	1,046
57		
58		**(MVA)**
59	Zone substation transformer capacity (EDB owned)	1,052
60	Zone substation transformer capacity (Non-EDB owned)	–
61	**Total zone substation transformer capacity**	1,052

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**
Network / Sub-network Name	**Dunedin Sub-network**

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref

9e(i): Consumer Connections and Decommissionings

sch ref			
9	*Number of ICPs connected during year by consumer type*		
10	*Consumer types defined by EDB**	**Number of connections (ICPs)**	
11	Residential	315	
	Load Group 0	3	
	Load Group 0A	28	
	Load Group 1A	1	
	Load Group 1	–	
	Load Group 2	28	
	Load Group 3	3	
	Load Group 3A	2	
12	Load Group 4	2	
13	Load Group 5	–	
14	Street Lighting	2	
15	Distributed Unmetered Load (excl. Street Lighting)	–	
16	** include additional rows if needed*		
17	**Connections total**	384	
18			
19	*Number of ICPs decommissioned during year by consumer type*		
20	*Consumer types defined by EDB**	**Number of decommissionings**	
21	Residential	95	
	Load Group 0	2	
	Load Group 0A	13	
	Load Group 1A	8	
	Load Group 1	9	
	Load Group 2	18	
	Load Group 3	–	
	Load Group 3A	–	
22	Load Group 4	1	
23	Load Group 5	–	
24	Street Lighting	–	
25	Distributed Unmetered Load (excl. Street Lighting)	–	
26	** include additional rows if needed*		
27	**Decommissionings total**	146	
28			
29	**Distributed generation**		
30	Number of connections made in year	146	**connections**
31	Capacity of distributed generation installed in year	0.79	**MVA**
32			

9e(ii): System Demand

sch ref				
34				
35				
36		**Maximum coincident system demand**	**Demand at time of maximum coincident demand (MW)**	
37		GXP demand	157	
38	*plus*	Distributed generation output at HV and above	28	
39		**Maximum coincident system demand**	186	
40	*less*	Net transfers to (from) other EDBs at HV and above	–	
41		**Demand on system for supply to consumers' connection points**	186	
42		**Electricity volumes carried**	**Energy (GWh)**	
43		Electricity supplied from GXPs	659	
44	*less*	Electricity exports to GXPs	0	
45	*plus*	Electricity supplied from distributed generation	170	
46	*less*	Net electricity supplied to (from) other EDBs	–	
47		**Electricity entering system for supply to consumers' connection points**	829	
48	*less*	Total energy delivered to ICPs	813	
49		**Electricity losses (loss ratio)**	16	1.9%
50				
51		**Load factor**	0.51	

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**
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).

9e(iii): Transformer Capacity

	(MVA)
Distribution transformer capacity (EDB owned)	490
Distribution transformer capacity (Non-EDB owned)	41
Total distribution transformer capacity	531

	(MVA)
Zone substation transformer capacity (EDB owned)	604
Zone substation transformer capacity (Non-EDB owned)	–
Total zone substation transformer capacity	604

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**
Network / Sub-network Name	**Central Otago & Wanaka Sub-network**

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref			
8	**9e(i): Consumer Connections and Decommissionings**		
9	*Number of ICPs connected during year by consumer type*		
10	*Consumer types defined by EDB**	**Number of connections (ICPs)**	
11	Residential	458	
	Load Group 0	1	
	Load Group 0A	–	
	Load Group 1A	19	
	Load Group 1	28	
	Load Group 2	93	
	Load Group 3	5	
	Load Group 3A	7	
12	Load Group 4	–	
13	Load Group 5	–	
14	Street Lighting	–	
15	Distributed Unmetered Load (excl. Street Lighting)	–	
16	** include additional rows if needed*		
17	**Connections total**	611	
18			
19	*Number of ICPs decommissioned during year by consumer type*		
20	*Consumer types defined by EDB**	**Number of decommissionings**	
21	Residential	30	
	Load Group 0	2	
	Load Group 0A	79	
	Load Group 1A	1	
	Load Group 1	12	
	Load Group 2	15	
	Load Group 3	–	
	Load Group 3A	–	
22	Load Group 4	1	
23	Load Group 5	–	
24	Street Lighting	–	
25	Distributed Unmetered Load (excl. Street Lighting)	–	
26	** include additional rows if needed*		
27	**Decommissionings total**	140	
28			
29	**Distributed generation**		
30	Number of connections made in year	356	**connections**
31	Capacity of distributed generation installed in year	3.67	**MVA**
32			
33	**9e(ii): System Demand**		
34			
35			
36	**Maximum coincident system demand**	**Demand at time of maximum coincident demand (MW)**	
37	GXP demand	44	
38	*plus* Distributed generation output at HV and above	23	
39	**Maximum coincident system demand**	67	
40	*less* Net transfers to (from) other EDBs at HV and above	–	
41	**Demand on system for supply to consumers' connection points**	67	
42	**Electricity volumes carried**	**Energy (GWh)**	
43	Electricity supplied from GXPs	219	
44	*less* Electricity exports to GXPs	53	
45	*plus* Electricity supplied from distributed generation	186	
46	*less* Net electricity supplied to (from) other EDBs	5	
47	**Electricity entering system for supply to consumers' connection points**	347	
48	*less* Total energy delivered to ICPs	329	
49	**Electricity losses (loss ratio)**	18	5.1%
50			
51	**Load factor**	0.59	

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**
Network / Sub-network Name	**Central Otago & 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).

9e(iii): Transformer Capacity

53		**(MVA)**
54	Distribution transformer capacity (EDB owned)	306
55	Distribution transformer capacity (Non-EDB owned)	21
56	**Total distribution transformer capacity**	327
57		
58		**(MVA)**
59	Zone substation transformer capacity (EDB owned)	284
60	Zone substation transformer capacity (Non-EDB owned)	–
61	**Total zone substation transformer capacity**	284

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**
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 and Decommissionings

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

sch ref	*Consumer types defined by EDB**	Number of connections (ICPs)
10		
11	Residential	128
	Load Group 0	–
	Load Group 0A	–
	Load Group 1A	2
	Load Group 1	–
	Load Group 2	93
	Load Group 3	2
	Load Group 3A	3
12	Load Group 4	2
13	Load Group 5	–
14	Street Lighting	–
15	Distributed Unmetered Load (excl. Street Lighting)	–
16	** include additional rows if needed*	
17	**Connections total**	230
18		

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

sch ref	*Consumer types defined by EDB**	Number of decommissionings
20		
21	Residential	23
	Load Group 0	1
	Load Group 0A	24
	Load Group 1A	–
	Load Group 1	8
	Load Group 2	9
	Load Group 3	–
	Load Group 3A	1
22	Load Group 4	–
23	Load Group 5	–
24	Street Lighting	–
25	Distributed Unmetered Load (excl. Street Lighting)	–
26	** include additional rows if needed*	
27	**Decommissionings total**	66
28		

29 Distributed generation

sch ref			
30	Number of connections made in year	158	**connections**
31	Capacity of distributed generation installed in year	0.89	**MVA**
32			

33 9e(ii): System Demand

sch ref			Demand at time of maximum coincident demand (MW)
34			
35			
36		**Maximum coincident system demand**	
37		GXP demand	67
38	*plus*	Distributed generation output at HV and above	2
39		**Maximum coincident system demand**	69
40	*less*	Net transfers to (from) other EDBs at HV and above	–
41		**Demand on system for supply to consumers' connection points**	69

sch ref			Energy (GWh)	
42		**Electricity volumes carried**		
43		Electricity supplied from GXPs	274	
44	*less*	Electricity exports to GXPs	–	
45	*plus*	Electricity supplied from distributed generation	17	
46	*less*	Net electricity supplied to (from) other EDBs	–	
47		**Electricity entering system for supply to consumers' connection points**	291	
48	*less*	Total energy delivered to ICPs	281	
49		**Electricity losses (loss ratio)**	10	3.4%
50				
51		**Load factor**	0.48	

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**
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).

9e(iii): Transformer Capacity

	(MVA)
Distribution transformer capacity (EDB owned)	183
Distribution transformer capacity (Non-EDB owned)	5
Total distribution transformer capacity	188

	(MVA)
Zone substation transformer capacity (EDB owned)	164
Zone substation transformer capacity (Non-EDB owned)	–
Total zone substation transformer capacity	164

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**
Network / Sub-network Name	**Total Network**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

8 10(i): Interruptions

sch ref	Interruptions by class	Number of interruptions
9	**Interruptions by class**	
10	Class A (planned interruptions by Transpower)	–
11	Class B (planned interruptions on the network)	1,151
12	Class C (unplanned interruptions on the network)	738
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)	10
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)	3
19	**Total**	1,902
20		

sch ref	Interruption restoration	≤3Hrs	>3hrs
21	**Interruption restoration**		
22	Class C interruptions restored within	521	217
23			

sch ref	SAIFI and SAIDI by class	SAIFI	SAIDI
24	**SAIFI and SAIDI by class**		
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.76	210.8
27	Class C (unplanned interruptions on the network)	1.85	139.1
28	Class D (unplanned interruptions by Transpower)	–	–
29	Class E (unplanned interruptions of EDB owned generation)	–	–
30	Class F (unplanned interruptions of generation owned by others)	0.00	0.2
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	0.0
34	**Total**	2.60	350.1
35			

sch ref	Normalised SAIFI and SAIDI	Normalised SAIFI	Normalised SAIDI	
36	**Normalised SAIFI and SAIDI**			
37	Classes B & C (interruptions on the network)	2.60	347.1	*Not required after DY2024*
38				

sch ref	Transitional SAIFI and SAIDI (previous method)	SAIFI	SAIDI
39	**Transitional SAIFI and SAIDI (previous method)**		
40	Class B (planned interruptions on the network)		
41	Class C (unplanned interruptions on the network)		
42			

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**
Network / Sub-network Name	**Total Network**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

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

Cause	SAIFI	SAIDI	
Lightning	0.01	2.2	
Vegetation	0.20	18.1	
Adverse weather	0.02	0.8	
Adverse environment	0.03	1.8	
Third party interference	0.12	8.5	
Wildlife	0.05	4.4	
Human error	0.18	5.9	
Defective equipment	0.61	46.3	
Cause unknown	0.64	51.2	*Not required after DY2024*
Other cause			*Not required before DY2025*
Unknown			*Not required before DY2025*

Breakdown of third party interference	SAIFI	SAIDI
Dig-in	0.02	1.6
Overhead contact	0.04	1.3
Vandalism	–	–
Vehicle damage	0.05	5.6
Other	–	–

Breakdown of vegetation interruptions (vegetation cause)	SAIFI	SAIDI	
In-zone			*Not required before DY2026*
Out-of-zone			*Not required before DY2026*

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.00	0.4
Subtransmission cables	–	–
Subtransmission other	0.00	0.0
Distribution lines (excluding LV)	0.52	156.3
Distribution cables (excluding LV)	0.14	37.3
Distribution other (excluding LV)	0.09	16.7

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.37	32.9
Subtransmission cables	–	–
Subtransmission other	0.15	6.7
Distribution lines (excluding LV)	0.96	76.5
Distribution cables (excluding LV)	0.16	12.0
Distribution other (excluding LV)	0.21	11.0

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	22	522	4.21
Subtransmission cables	–	98	–
Subtransmission other	6		
Distribution lines (excluding LV)	255	2,278	11.19
Distribution cables (excluding LV)	41	1,219	3.36
Distribution other (excluding LV)	200		
Total	524		

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**
Network / Sub-network Name	**Total Network**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

10(vi): Worst-performing feeders (unplanned)

Not required before DY2025

SAIDI

Rank	Feeder name	Unplanned SAIDI values	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1							
2							
3							
4							

[1] *Extend table as necessary to disclose all worst-performing feeders*

SAIFI

Rank	Feeder name	Unplanned SAIFI values	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1							
2							
3							
4							

[1] *Extend table as necessary to disclose all worst-performing feeders*

Customer Impact

Rank	Feeder name	Customer Impact Ratio	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1							
2							
3							
4							

[1] *Extend table as necessary to disclose all worst-performing feeders*

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**
Network / Sub-network Name	**Dunedin Sub-network**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

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)	584	
12	Class C (unplanned interruptions on the network)	253	
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**	837	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	187	66
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.68	155.0
27	Class C (unplanned interruptions on the network)	0.78	51.4
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**	1.45	206.4
35			
36	**Normalised SAIFI and SAIDI**	**Normalised SAIFI**	**Normalised SAIDI**
37	Classes B & C (interruptions on the network)	N/A	N/A *Not required after DY2024*
38			
39	**Transitional SAIFI and SAIDI (previous method)**	**SAIFI**	**SAIDI**
40	Class B (planned interruptions on the network)		
41	Class C (unplanned interruptions on the network)		
42			

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**
Network / Sub-network Name	**Dunedin Sub-network**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

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

Cause	SAIFI	SAIDI	
Lightning	0.00	0.0	
Vegetation	0.09	10.6	
Adverse weather	0.03	1.4	
Adverse environment	0.01	0.0	
Third party interference	0.11	8.8	
Wildlife	0.02	1.8	
Human error	0.04	1.9	
Defective equipment	0.40	21.4	
Cause unknown	0.07	5.5	*Not required after DY2024*
Other cause			*Not required before DY2025*
Unknown			*Not required before DY2025*

Breakdown of third party interference	SAIFI	SAIDI
Dig-in	0.03	2.0
Overhead contact	0.01	0.2
Vandalism	–	–
Vehicle damage	0.07	6.7
Other	–	–

Breakdown of vegetation interruptions (vegetation cause)	SAIFI	SAIDI	
In-zone			*Not required before DY2026*
Out-of-zone			*Not required before DY2026*

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)	0.49	126.0
Distribution cables (excluding LV)	0.08	16.1
Distribution other (excluding LV)	0.11	12.8

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.07	0.6
Subtransmission cables	–	–
Subtransmission other	0.01	0.2
Distribution lines (excluding LV)	0.40	35.1
Distribution cables (excluding LV)	0.16	8.3
Distribution other (excluding LV)	0.14	7.1

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	2	144	1.39
Subtransmission cables	–	66	–
Subtransmission other	2		
Distribution lines (excluding LV)	70	730	9.59
Distribution cables (excluding LV)	18	332	5.42
Distribution other (excluding LV)	86		
Total	178		

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**
Network / Sub-network Name	**Dunedin Sub-network**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

10(vi): Worst-performing feeders (unplanned)

Not required before DY2025

SAIDI

Rank	Feeder name	Unplanned SAIDI values	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1							
2							
3							
4							

[1] *Extend table as necessary to disclose all worst-performing feeders*

SAIFI

Rank	Feeder name	Unplanned SAIFI values	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1							
2							
3							
4							

[1] *Extend table as necessary to disclose all worst-performing feeders*

Customer Impact

Rank	Feeder name	Customer Impact Ratio	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1							
2							
3							
4							

[1] *Extend table as necessary to disclose all worst-performing feeders*

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**
Network / Sub-network Name	**Central Otago & Wanaka Sub-network**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

8 **10(i): Interruptions**

sch ref		Number of interruptions
9	**Interruptions by class**	
10	Class A (planned interruptions by Transpower)	–
11	Class B (planned interruptions on the network)	414
12	Class C (unplanned interruptions on the network)	347
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)	10
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)	3
19	**Total**	774
20		

sch ref		≤3Hrs	>3hrs
21	**Interruption restoration**		
22	Class C interruptions restored within	242	105
23			

sch ref		SAIFI	SAIDI
24	**SAIFI and SAIDI by class**		
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.87	283.3
27	Class C (unplanned interruptions on the network)	4.52	344.4
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	0.6
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	0.1
34	**Total**	5.39	628.4
35			

sch ref		Normalised SAIFI	Normalised SAIDI	
36	**Normalised SAIFI and SAIDI**			
37	Classes B & C (interruptions on the network)	N/A	N/A	*Not required after DY2024*
38				

sch ref		SAIFI	SAIDI
39	**Transitional SAIFI and SAIDI (previous method)**		
40	Class B (planned interruptions on the network)		
41	Class C (unplanned interruptions on the network)		
42			

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**
Network / Sub-network Name	**Central Otago & Wanaka Sub-network**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

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

Cause	SAIFI	SAIDI	
Lightning	0.04	9.0	
Vegetation	0.35	30.1	
Adverse weather	–	–	
Adverse environment	0.07	7.4	
Third party interference	0.19	7.9	
Wildlife	0.09	8.3	
Human error	0.57	18.1	
Defective equipment	0.95	79.8	
Cause unknown	2.25	183.7	*Not required after DY2024*
Other cause			*Not required before DY2025*
Unknown			*Not required before DY2025*

Breakdown of third party interference	SAIFI	SAIDI
Dig-in	0.00	0.1
Overhead contact	0.16	4.7
Vandalism	–	–
Vehicle damage	0.02	3.2
Other	–	–

Breakdown of vegetation interruptions (vegetation cause)	SAIFI	SAIDI	
In-zone			*Not required before DY2026*
Out-of-zone			*Not required before DY2026*

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.00	0.3
Subtransmission cables	–	–
Subtransmission other	0.00	0.0
Distribution lines (excluding LV)	0.62	214.6
Distribution cables (excluding LV)	0.21	55.7
Distribution other (excluding LV)	0.03	12.7

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	1.29	125.3
Subtransmission cables	–	–
Subtransmission other	0.53	26.5
Distribution lines (excluding LV)	2.17	158.5
Distribution cables (excluding LV)	0.19	21.6
Distribution other (excluding LV)	0.34	12.6

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	15	309	4.85
Subtransmission cables	–	10	–
Subtransmission other	3		
Distribution lines (excluding LV)	141	1,273	11.08
Distribution cables (excluding LV)	13	589	2.21
Distribution other (excluding LV)	86		
Total	258		

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**
Network / Sub-network Name	**Central Otago & Wanaka Sub-network**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

10(vi): Worst-performing feeders (unplanned)

Not required before DY2025

SAIDI

Rank	Feeder name	Unplanned SAIDI values	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1							
2							
3							
4							

[1] *Extend table as necessary to disclose all worst-performing feeders*

SAIFI

Rank	Feeder name	Unplanned SAIFI values	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1							
2							
3							
4							

[1] *Extend table as necessary to disclose all worst-performing feeders*

Customer Impact

Rank	Feeder name	Customer Impact Ratio	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1							
2							
3							
4							

[1] *Extend table as necessary to disclose all worst-performing feeders*

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**
Network / Sub-network Name	**Queenstown Sub-network**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

8 **10(i): Interruptions**

sch ref	Interruptions by class	Number of interruptions
10	Class A (planned interruptions by Transpower)	–
11	Class B (planned interruptions on the network)	153
12	Class C (unplanned interruptions on the network)	138
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**	291

sch ref	Interruption restoration	≤3Hrs	>3hrs
22	Class C interruptions restored within	92	46

sch ref	SAIFI and SAIDI by class	SAIFI	SAIDI
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.89	308.6
27	Class C (unplanned interruptions on the network)	1.71	150.2
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**	2.60	458.8

sch ref	Normalised SAIFI and SAIDI	Normalised SAIFI	Normalised SAIDI	
37	Classes B & C (interruptions on the network)	N/A	N/A	*Not required after DY2024*

sch ref	Transitional SAIFI and SAIDI (previous method)	SAIFI	SAIDI
40	Class B (planned interruptions on the network)		
41	Class C (unplanned interruptions on the network)		

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

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**
Network / Sub-network Name	**Queenstown Sub-network**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

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

Cause	**SAIFI**	**SAIDI**	
Lightning	0.00	0.0	
Vegetation	0.34	27.8	
Adverse weather	–	–	
Adverse environment	–	–	
Third party interference	0.05	7.8	
Wildlife	0.08	7.8	
Human error	0.10	2.1	
Defective equipment	0.86	88.2	
Cause unknown	0.27	16.5	*Not required after DY2024*
Other cause			*Not required before DY2025*
Unknown			*Not required before DY2025*

Breakdown of third party interference	**SAIFI**	**SAIDI**
Dig-in	0.02	2.4
Overhead contact	–	–
Vandalism	–	–
Vehicle damage	0.03	5.4
Other	–	–

Breakdown of vegetation interruptions (vegetation cause)	**SAIFI**	**SAIDI**	
In-zone			*Not required before DY2026*
Out-of-zone			*Not required before DY2026*

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

Main equipment involved	**SAIFI**	**SAIDI**
Subtransmission lines	0.00	1.8
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	0.48	179.9
Distribution cables (excluding LV)	0.30	89.0
Distribution other (excluding LV)	0.10	37.9

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

Main equipment involved	**SAIFI**	**SAIDI**
Subtransmission lines	0.10	10.6
Subtransmission cables	–	–
Subtransmission other	0.06	0.7
Distribution lines (excluding LV)	1.19	104.8
Distribution cables (excluding LV)	0.09	11.4
Distribution other (excluding LV)	0.26	22.8

10(v): Fault Rate

Main equipment involved	**Number of Faults**	**Circuit length (km)**	**Fault rate (faults per 100km)**
Subtransmission lines	5	69	7.25
Subtransmission cables	–	22	–
Subtransmission other	1		
Distribution lines (excluding LV)	44	282	15.60
Distribution cables (excluding LV)	10	296	3.38
Distribution other (excluding LV)	28		
Total	88		

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2024**
Network / Sub-network Name	**Queenstown Sub-network**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

10(vi): Worst-performing feeders (unplanned)

Not required before DY2025

SAIDI

Rank	Feeder name	Unplanned SAIDI values	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1							
2							
3							
4							

[1] *Extend table as necessary to disclose all worst-performing feeders*

SAIFI

Rank	Feeder name	Unplanned SAIFI values	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1							
2							
3							
4							

[1] *Extend table as necessary to disclose all worst-performing feeders*

Customer Impact

Rank	Feeder name	Customer Impact Ratio	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1							
2							
3							
4							

[1] *Extend table as necessary to disclose all worst-performing feeders*

Company Name	Aurora Energy Limited
For Year Ended	31 March 2024

Schedule 14 Mandatory Explanatory Notes

1. This schedule requires EDBs to provide explanatory notes to information provided in accordance with clauses 2.3.1, 2.4.21, 2.4.22, and subclauses 2.5.1(1)(f),and 2.5.2(1)(e).

2. This schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.1. Information provided in boxes 1 to 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.

Return on Investment (Schedule 2)

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

Box 1: Explanatory comment on return on investment-

The RY24 ROI exceeded the estimated WACC used to set Aurora Energy's price path. The RY24 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 RAB revaluation.

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.

The opex IRIS incentive for RY24 is a positive adjustment of $20.937 mil that relates to operational expenditure allowances from the previous regulatory period. The capex IRIS incentive for RY24 is a penalty of $1.537 mil for overspending capital expenditure allowances in the previous regulatory period. These incentives were included in the company's calculation of allowable revenue when setting prices for RY24.

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 customer 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 exceeded, should receive a greater share of the money being returned.

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

Regulatory Profit (Schedule 3)

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

   5.1 a description of material items included in other regulated income (other than gains / (losses) on asset disposals), as disclosed in 3(i) of Schedule 3; and

   5.2 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 2024 is $67.3 mil before tax. This is $7.3 mil higher than the previous year. The movement comprised of higher line revenue (+$20.6 mil), lower pass-through and recoverable costs (-$2.1 mil), lower revaluations (-$13.2 mil) and higher depreciation (+$3.3 mil) for the year.

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

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

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

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

Box 3: Explanatory comment on merger and acquisition expenditure

There were no merger and acquisition costs incurred.

Value of the Regulatory Asset Base (Schedule 4)

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

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

The Regulatory Asset Base (RAB) increased by $94.0mil during the year (2023: $90.8 mil). Commissioned asset values were $18.8 mil higher than in the previous year, asset disposals declined by $0.9 mil, revaluations declined by $13.2 mil and depreciation charges increased by $3.3 mil for the year.

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

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

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

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

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

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

Box 5: Regulatory tax allowance: permanent differences

The amount of $45,901 relating to 'Expenditure or loss in regulatory profit or (loss) before tax but not deductible' is non-deductible entertainment. The amount of $1,042,468 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)

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

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

Temporary timing differences of $1,378,374 recorded in the current disclosure year relate to the tax effect of income spreading over 10 years on capital initiated works (+$1,587,000), downward movement in provision for expected credit losses (doubtful debts) (-$29,400) and decrease in employee entitlements (-$179,226).

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

Cost allocation (Schedule 5d)

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

Box 7: Cost allocation

All 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)

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

Box 8: Commentary on asset allocation

Other network assets includes a fibre network that comprises of ducting / high speed broadband fibre utilised for communications between the Dunedin zone sub-station sites. It is assessed that for RY24, 75.5% of the network is utilised for communications between the Dunedin zone sub-station sites (RY23: 75.5%).

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

Capital Expenditure for the Disclosure Year (Schedule 6a)

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

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

    12.2 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 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)

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

    13.1 Commentary on assets replaced or renewed with asset replacement and renewal operational expenditure, as reported in 6b(i) of Schedule 6b;

    13.2 Information on reclassified items in accordance with subclause 2.7.1(2);

    13.3 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

RY24 opex was $48.0 mil, this was $3.6 mil lower than the RY24 target.

RY24 network maintenance was $3.2 mil below target of $20.8 mil, due to a $3.7 mil underspend on corrective and preventative maintenance. Vegetation management expenditure was $0.6 mil above the RY24 target.

RY24 non-network opex was $0.4 mil below target at $30.8 mil. Components of the underspend included:

- SONS expenditure was circa $0.7 mil above target after an underspend in network evolution/Upper Clutha DER of $0.8 mil. Other SONS expenditure was $1.3 mil above target largely due to the reclassification of IT expenditure per note below*.

- Business support expenditure was circa $1.1 mil below target inclusive of underspends in IT (-$0.7 mil)*, people costs (-$0.3 mil) , and administration and governance (-$0.1 mil).

*$1.1 mil of RY24 IT costs were reclassified as SONS expenditure following a change in the primary driver of operational technology projects. The RY24 target assumed these projects would be classified as Business Support.

Variance between forecast and actual expenditure (Schedule 7)

14. 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 $12.4 mil (13%) higher than forecast.

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 "capacity event" projects. Aurora Energy has applied to the Commerce Commission for a price-path reopener to accommodate higher levels of growth-related demand.

The asset replacement and renewal expenditure was within 5% (it was 4%) of forecast for the year.

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

Non-network capex was higher than expected largely due to new leases (+$1.2 mil) recognised under IFRS 16 as right-of-use assets.

Service interruptions and emergencies expenditure was within 1% of forecast for the year.

Routine and corrective maintenance and inspection underspend was primarily due to:

1. Efficiencies made in the area of overhead inspection work.
2. A delayed start date to the initiative to inspect and remediate consumer owned poles and service lines.

Due to lower routine and corrective maintenance expenditure, we directed additional expenditure to vegetation management.

Information relating to revenues and quantities for the disclosure year

15. In the box below provide-

15.1 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

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

Box 12: Explanatory comment relating to revenue for the disclosure year-

Total Revenue:

The forecast revenue from line charges was $140.874 million (Annual Price-Setting Compliance Statement – 1 April 2023).

In Schedule 8 (Total Network), we have reported total line charge revenue of $143.776 million. This is a difference of $2.902 million (2.1%) above target. It is generally expected that total billed line charge revenue for an assessment period will be different from target revenue due to variation in connection numbers and energy demand.

Residential Revenue:

In this assessment period, the volume of energy delivered to Residential consumers (the only consumer groups with volume-based pricing) increased from the prior year (by 7.4%). Energy delivered to Residential connections for the year ended 31 March 2024 was 675.9 GWh compared with 629.6 GWh last year.

The average number of Residential connections increased by 1.0% during the assessment period. The average number of residential connections for the year ended 31 March 2024 was 79,726, compared with 78,946 for the previous year.

The average energy use per Residential consumer in this assessment period has increased by 6.3% from 7,975 kWh for the year ended 31 March 2023 to 8,478 kWh in this assessment period.

General Revenue:

The average number of General connections, which are priced predominantly on the basis of demand and capacity, increased from 15,365 in RY23 to 15,503 in this assessment period (0.9%).

The distinction between Residential and General connections is explained in section 5 of Aurora Energy's Use-of-System Pricing Methodology, available from https://www.auroraenergy.co.nz/disclosures/pricing-methodologies

Network Reliability for the Disclosure Year (Schedule 10)

16. 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 (2024), available from https://www.auroraenergy.co.nz/disclosures/price-quality-path/

Insurance cover

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

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

    17.2 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 other distribution assets e.g. distribution transformers and switches.

Distribution line 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

18. 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:

    18.1 a description of each error; and

    18.2 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 material errors in previously disclosed information requiring amendment.

Please refer to Schedule 15 for information on a prior period understatement related to the deferred tax balance, which is corrected in the current disclosure year. We have assessed this as non-material, and pursuant to the discretion in clause 12.2.2 of the ID Determination we have chosen not to publicly disclose it in accordance with clause 12.2.1.

Company Name	Aurora Energy Limited
For Year Ended	31 March 2024

Schedule 15 Voluntary Explanatory Notes

1. This schedule enables an EDB to provide, should they wish to-

   1.1 additional explanatory comment to reports prepared in accordance with clauses 2.3.1, 2.4.21, 2.4.22, 2.5.1, 2.5.2, and 2.6.6:

   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

Schedule 5a: Regulatory Tax Allowance

The deferred tax balance as at 31 March 2023 was understated by $0.366m.

The difference in the deferred tax balance related to an understatement in the temporary difference calculation of the tax effect of income spreading over 10 years.

We have put an adjustment of $0.366m through the current year timing differences in Schedule 5a(vi) to correct this.

Schedule 8 - Total Transmission Line Charge Revenue

Consistent with previous years, total transmission line charge revenue also includes all passthrough and recoverable costs recovered through lines charges.

RELATED PARTIES TRANSACTIONS

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 2024.

RELATED PARTY	RELATIONSHIP BETWEEN AURORA AND THE RELATED PARTY	PRINCIPAL ACTIVITIES OF THE RELATED PARTY	TOTAL ANNUAL EXPENDITURE INCURRED BY AURORA ENERGY WITH THE RELATED PARTY
Delta Utility Services Limited (Delta)	Aurora Energy and Delta are related as DCHL is the ultimate holding company of Aurora Energy and Delta. DCHL is the sole shareholder of Delta.	Delta is a multi-utility services contractor providing a range of electrical and other services to local authority and private sector clients. The principal activities of Delta are the management, construction, operation and maintenance of electricity and metering infrastructure assets, and the provision of environmental contracting and related services.	$54,944,000 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.	$1,318 ,000 This expenditure is primarily in relation to local rates that are payable to the DCC.
Dunedin City Treasury Limited (DCTL)	Aurora Energy and DCTL are related as DCHL is the ultimate holding company of Aurora Energy and DCTL. DCHL is the sole shareholder of DCTL.	DCTL provides funding and financial services to the other entities in the Dunedin City Holdings Limited group.	$830,000 This expenditure is in relation to interest payable by Aurora Energy to DCTL that has been capitalised.

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 97,000 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 Energy Approved Contractor).
Network and non-network capital expenditure: • system growth • reliability, safety and environment • asset replacement and renewal • asset relocations • non-system fixed assets (ie IT systems, asset management systems, office buildings and furniture, motor vehicles).	• Panel arrangement • Direct procurement • Tender • All-of-Government

3 Application of procurement policy

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

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

3.1.1 Field Services Agreements

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

The separation reinforces that Aurora Energy has a clear responsibility to seek the best available services from the market on behalf of its customers. In order to achieve this, we introduced contestable performance-based service delivery arrangements with two additional field service providers being contract to carry out renewal, maintenance and development work from 1 April 2019 - Unison Contracting based in Dunedin, and Connetics based in Central Otago.

This arrangement between the three contractors was consolidated in the field services agreement (FSA) that we entered into with each contractor. Each FSA had an initial term of three years, which provided 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 therefore became five-year agreements, which expired on 31 March 2024.

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

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

We have recently concluded the process of appointing field service providers for a new 4-year period from 1 April 2024. This process entailed running a tender process, at the end of which Delta and Unison were re-appointed as field service providers. We have appointed ElectroNet as a Secondary Service Provider in the Central Otago region and Asplundh in Dunedin to perform vegetation services.

With Unison having now well established themselves as a Secondary Service Provider, we have continued 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 now ElectroNet and Asplundh 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 our partners with sufficient work to ensure their viability on our network.

3.1.2 External tender market

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

3.1.3 Engineering Services Consultancy Panel

We also have established an Engineering Services Consultancy Panel to provide specific electricity design services for asset replacement and renewal projects and growth projects. The panel consists of engineering consulting companies and included Delta until July 2023.

3.1.4 Customer Initiated Works

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

3.1.5 Vegetation Services Agreement

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

3.1.6 Internal controls

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

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

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

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

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

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

EXPENDITURE CATEGORY	REPRESENTATIVE EXAMPLE	PROCUREMENT METHOD	HOW AND WHEN ARM'S LENGTH TERMS LAST TESTED
Capital expenditure			
System growth	Reinforcement of low voltage network	Services were procured through the negotiated FSA	The terms upon which services are provided, and the rates at which services are charged, were tested in 2018 during the development of the three FSAs.
Asset replacement and renewal	Replacement of poles	Services were procured through the negotiated FSA.	The terms upon which services are provided, and the rates at which services are charged, were tested in 2018 during the development of the three FSAs.
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 recloser	Services were procured through the negotiated FSA.	The terms upon which services are provided, and the rates at which services are charged, were tested in 2018 during the development of the three FSAs.
Non-network assets	Procurement of locks for assisting in ensuring the safety of people operating the network	Direct procurement	Not tested.

4 Map of anticipated network expenditure and network constraints

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

4.1 Top 10 operational and capital expenditure programmes and projects

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

4.1.1 Operational expenditure programmes and projects

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

- preventative 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.	**Preventative Maintenance** This programme encompasses routine maintenance activities including testing, inspections, condition assessments and servicing.	RY25—34	$ 112.0 million	Total network	This programme of works is covered by three FSA providers, each of which have a four year term from 1 April 2024 to 31 March 2028.

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 incorporated high level and lower level programmes (where possible) into the top 10 list to show visibility of high value works of similar type. 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 RY25.				Delta, a related party, is one of the field service providers. We expect the work to be allocated among the three FSA providers, and other Approved Contractors.
1a.	**Pole Inspections** This programme of works encompasses the preventive inspection of poles on the Aurora Energy network.	RY25	$ 2.1 million	Total network	This programme of works is covered by three FSA providers, each of which have a four year term from 1 April 2024 to 31 March 2028. Delta, a related party, is one of the field service providers. We expect the work to be allocated among the three FSA providers, and other Approved Contractors.
1b.	**Zone Substation Preventive Maintenance** This programme of works encompasses the carrying out of preventive maintenance in Aurora Energy's zone substations.	RY25	$ 1.7 million	Total network	This programme of works is covered by three FSA providers, each of which have a four year term from 1 April 2024 to 31 March 2028. Delta, a related party, is one of the field service providers. We expect the work to be allocated among the three FSA providers, and other Approved Contractors.
1c.	**RMU Preventive Maintenance**	RY25	$ 1.3 million	Total network	This programme of works is covered by three FSA providers, each of which have a four year term from 1 April 2024 to 31 March 2028.

	DESCRIPTION OF THE PROJECT (INCLUDING ANY POSSIBLE FUTURE NETWORK OR EQUIPMENT CONSTRAINT THAT THE PROJECT ADDRESSES)	LIKELY TIMING OF THE PROJECT	LIKELY VALUE OF THE PROJECT	LOCATION OF THE PROJECT	CONTRACTUAL STATUS
	This programme of works encompasses the carrying out of preventive maintenance on Aurora Energy's RMUs.				Delta, a related party, is one of the field service providers. We expect the work to be allocated among the three FSA providers, and other Approved Contractors.
1d.	**Ground and pole mounted transformer inspections** This programme of work encompasses the carrying out of preventative inspections on Aurora Energy's mounted transformers.	RY25	$ 1.0 million	Total network	This programme of works is covered by three FSA providers, each of which have a four year term from 1 April 2024 to 31 March 2028. Delta, a related party, is one of the field service providers. We expect the work to be allocated among the three FSA providers, and other Approved Contractors.
1e.	**Overhead Conductor Inspections** This programme of works encompasses the carrying out of preventive inspections on Aurora Energy's overhead conductors.	RY25	$ 0.7 million	Total network	This programme of works is covered by three FSA providers, each of which have a four year term from 1 April 2024 to 31 March 2028. Delta, a related party, is one of the field service providers. We expect the work to be allocated among the three FSA providers, and other Approved Contractors.
2.	**Corrective Maintenance** Primarily involves remediating defects, by replacing components or minor assets, or undertaking repairs. Corrective work may be	RY25-34	$ 58.5 million	Total network	This programme of works is covered by three FSA providers, each of which have a four year term from 1 April 2024 to 31 March 2028.

	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
	identified during preventive maintenance or fault response. Programme 2a below is encompassed within this category of expenditure.				Delta, a related party, is one of the field service providers. We expect the work to be allocated among the three FSA providers, and other Approved Contractors.
2a.	**Possum and Cable Guard Retrofit Programme** This programme of work encompasses the retrofitting of possum guards and cable guards on the Aurora network.	RY24-26	$ 0.4 million	Total network	This programme of works is covered by three FSA providers, each of which have a four year term from 1 April 2024 to 31 March 2028. Delta, a related party, is one of the field service providers. We expect the work to be allocated among the three FSA providers, and other Approved Contractors.
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 and the carrying out of preliminary and physical works.	RY25-34	$ 44.4 million	Total network	This programme of works is covered by two providers, across three VSAs. Two of the VSAs each have a four year term, from 1 April 2024 to 31 March 2028, with the Frankton VSA having a five year term from 1 April 2022 to 31 March 2027. Two of the three VSAs are with Delta, a related party. We expect the work to be allocated across the two VSA 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
4.	**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.	RY25-34	$ 41.9million	Total network	This programme of works is covered by three FSA providers, each of which have a four year term from 1 April 2024 to 31 March 2028. Delta, a related party, is one of the field service providers. 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.

4.1.2 Capital expenditure programmes and projects

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

DESCRIPTION OF THE PROJECT (INCLUDING ANY POSSIBLE FUTURE NETWORK OR EQUIPMENT CONSTRAINT THAT THE PROJECT ADDRESSES)		LIKELY TIMING OF THE PROJECT	LIKELY VALUE OF THE PROJECT	LOCATION OF THE PROJECT	CONTRACTUAL STATUS
Capital expenditure					
1.	**Pole Replacement** This is an ongoing programme of work to replace poles on a condition basis. The replacements involve entire pole assemblies (with crossarms) and may include replacement of pole mounted equipment such as distribution transformers if these are also assessed as being at end of life.	RY25-34	$ 121.8 million	Total network	This programme of works is covered by three FSA providers, each of which have a four year term from 1 April 2024 to 31 March 2028. Delta, a related party, is one of the field service providers. 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.	RY25-34	$ 81.5 million	Specific zone substations located across the network	Currently not indicated for supply by a related party.
2a.	**Green Island Substation Rebuild** The equipment contained in the Green Island substation is near-end-of-life and requires renewal. The optimum solution is for the substation to be rebuilt on the existing site.	RY23-25	$ 10.0 million	Green Island, Dunedin	Currently not indicated for supply by a related party.
2b.	**Corstorphine Transformer Renewal** The power transformers at the Corstorphine substation are near end-of-life and require renewal.	RY32-34	$ 9.7 million	Corstorphine, Dunedin	Currently not indicated for supply by a related party.
2c.	**East Taieri Substation Renewal**	RY30-31	$ 9.4 million	Mosgiel, Dunedin	Currently not indicated for supply by a related party.

DESCRIPTION OF THE PROJECT (INCLUDING ANY POSSIBLE FUTURE NETWORK OR EQUIPMENT CONSTRAINT THAT THE PROJECT ADDRESSES)		LIKELY TIMING OF THE PROJECT	LIKELY VALUE OF THE PROJECT	LOCATION OF THE PROJECT	CONTRACTUAL STATUS
	The equipment contained in the East Taieri substation is near-end-of-life and requires renewal.				
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.	RY29-30	$ 8.8million	Willowbank, Dunedin	Currently not indicated for supply by a related party.
2e.	**Alexandra Substation Renewal** The equipment contained in the Alexandra substation is near-end-of-life and requires renewal. This project involves re-establishing the 11kV and 33kV switchgear in indoor buildings.	RY24-25	$ 8.0 million	Alexandra, Central Otago	Currently not indicated for supply by a related party.
2f.	**Smith Street Substation Renewal - Transformers** The equipment contained in the Smith Street substation is near-end-of-life and requires renewal. This project involves replacing the existing transformers (two off) with 33kV/11kV 16/24MVA transformers complete with on load tap changers. Additional works include oil containment system upgrade, cabling, protection and neutral earthing resisters.	RY27-29	$ 4.2 million	Smith Street, Dunedin	Currently not indicated for supply by a related party.
3.	**Distribution Conductor Replacement** This is an ongoing programme of work to replace distribution conductor that has reached end-of-life.	RY25-34	$ 57.6 million	Total network	This programme of works is covered by three FSA providers, each of which have a four year term from 1 April 2024 to 31 March 2028. Delta, a related party, is one of the field service 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 expect the work to be allocated among the three FSA providers, and other Approved Contractors.
4.	**New Upper Clutha 66kV Line** This project involves the installation of a new sub-transmission line in the Upper Clutha region.	RY25-29	$ 40.7 million	Central Otago	Currently not indicated for supply by a related party.
5.	**Ground Mounted Switchgear Replacements** This is an ongoing programme of work to replace ground mounted switchgear that has reached end-of-life.	RY25-34	$ 40.6 million	Total network	This programme of works is covered by three FSA providers, each of which have a four year term from 1 April 2024 to 31 March 2028. Delta, a related party, is one of the field service providers. We expect the work to be allocated among the three FSA providers, and other Approved Contractors.
6.	**Subtransmission Conductor Replacement** This is an ongoing programme of work to replace subtransmission conductor that has reached end-of-life.	RY25-34	$ 35.7 Million	Total Network	This programme of works is covered by three FSA providers, each of which have a four year term from 1 April 2024 to 31 March 2028. Delta, a related party, is one of the field service providers. We expect the work to be allocated among the three FSA providers, and other Approved Contractors.

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
6a.	**Waipori stages 2B – 6** This project involves conductor renewal on Waipori A, B and C overhead lines.	RY24-32	$ 31.8 Million	Dunedin	Currently not indicated for supply by a related party.
7.	**Low voltage Conductor Replacement** This is an ongoing programme of work to replace LV conductor that has reached end-of-life.	RY25-34	$ 33.3 million	Total network	This programme of works is covered by three FSA providers, each of which have a four year term from 1 April 2024 to 31 March 2028. Delta, a related party, is one of the field service providers. We expect the work to be allocated among the three FSA providers, and other Approved Contractors.
8.	**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 8a, 8b and 8c below describe three of the most significant projects.	RY25-34	$ 27.7 million	Dunedin	Currently not indicated for supply by a related party.
8a.	**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.	RY25-30	$ 10.4 million	Corstorphine, Dunedin	Currently not indicated for supply by a related party.
8b.	**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	RY29-33	$ 6.0 million	Willowbank, 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
	cables. It forms a part of our plan to gradually transition to a meshed sub-transmission network in the Dunedin CBD.				
8c.	**Kaikorai Valley Cable Replacement** This project involves the replacement of the existing PILC, 33 kV underground cables that run between the Halfway Bush GXP and the Kaikorai zone substation.	RY24-26	$ 4.9 million	Kaikorai Valley, Dunedin	Currently not indicated for supply by a related party.
9.	**Crossarm Replacement** This is an ongoing programme of work to replace crossarms on a condition basis.	RY25-34	$ 27.2 million	Total network	This programme of works is covered by three FSA providers, each of which have a four year term from 1 April 2024 to 31 March 2028. Delta, a related party, is one of the field service providers. We expect the work to be allocated among the three FSA providers, and other Approved Contractors.
10.	**Ancillary Distribution Sub Replacements** This is an ongoing programme of work to replace ancillary distribution substations that have reached end-of-life.	RY25-34	$ 11.1 million	Total network	This programme of works is covered by three FSA providers, each of which have a four year term from 1 April 2024 to 31 March 2028. Delta, a related party, is one of the field service providers. We expect the work to be allocated among the three FSA providers, and other Approved Contractors.

4.2 Maps

4.2.1 Dunedin sub-network

4.2.2 Central Otago & Wanaka and Queenstown sub-networks

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, 2.3.8-2.3.12, 2.4.21, 2.4.22, 2.5.1(a)-(f), 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.

Signed by:
Stephen Thompson
7A255518164B40D...
Stephen Richard Thompson

Signed by:
Janice Fredric
5369DF46E66E47C...
Janice Evelyn Fredric

29 August 2024

AUDIT NEW ZEALAND
Mana Arotake Aotearoa

Independent Assurance Report

To the directors of Aurora Energy Limited and to the Commerce Commission on the disclosure information for the disclosure year ended 31 March 2024 as required by the Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024 [2024] NZCC2

Aurora Energy Limited (the company) is required to disclose certain information under the Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024 [2024] NZCC2 (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, Chantelle Gernetzky, 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 2024 (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 (limited to the SAIDI and SAIFI information) 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).

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 International Standard on Assurance Engagements (New Zealand) 3000 (Revised) Assurance Engagements Other Than Audits or Reviews of Historical Financial Information ("ISAE (NZ) 3000 (Revised)") and the Standard on Assurance Engagements (SAE) 3100 (Revised) Compliance Engagements ("SAE 3100 (Revised)"), 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 $97 million and assets commissioned into the RAB amounted to $96 million, compared to total network operating expenditure of $48 million. The amount of capital expenditure is also significant relative to the RAB opening value of $830 million. Capital expenditure and assets commissioned into the RAB are a key assurance matter due to the significant judgement by company personnel and the auditor to assess whether the capital expenditure and assets	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; and • reconciling the assets commissioned from the regulatory fixed asset register to the additions disclosed in the audited financial statements and investigated any reconciling items.

Key assurance matter	How our procedures addressed the key assurance matter
commissioned into the RAB meets the definition set out in the 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 significant professional judgement by the auditor.	We obtained an understanding of the company's approach to identifying and valuing related-party transactions at arm's-length in accordance with the Determination and the IM Determination. The procedures we carried out to satisfy ourselves that related-party transactions are appropriately valued at a value not greater than arm's-length included: • testing the completeness of related-parties identified through review of board minutes, review of Companies Office records, and related-parties identified through detailed testing of transactions and balances in the annual financial statements audit; • reviewing the relevant policies for approval and negotiation of related-party transactions, and testing compliance with those policies; • reviewing and testing the field services agreement with related parties; • benchmarking the charges against quotations from non-related parties; • confirming the material accuracy of related party values disclosed, and compliance of their calculation with the Determination and the IM Determination; and • confirming related party transactions valued at the cost incurred by the related party to underlying records. Having carried out these procedures, we are satisfied that related party transactions are valued at arms-length.
Accuracy of the number and duration of electricity outages The company has a combination of manual and automated systems to identify outages and to record the duration of outages. This outage information is used to report the company's report on Network Reliability in schedule 10. If this information is inaccurate	We have obtained an understanding of the company's system to record electricity outages, and their duration. This included review of the company's definition of interruptions, planned interruptions, and major event days. Our procedures to assess the adequacy of the company's methods to identify and record electricity outages and their duration included:

Key assurance matter	How our procedures addressed the key assurance matter
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. As the exemption related to successive interruptions reporting no longer applies, EDBs are required to report a SAIDI and SAIFI value determined using the "multi-count approach". The "multi-count approach" requires the company to record successive interruptions as an additional SAIFI and SAIDI value if restoration of supply occurs for longer than one minute. The company has previously reported using the "muti-count approach" and therefore no changes to processes and reporting are expected.	• reviewing and testing the overall control environment; • 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, 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; • checking the SAIDI and SAIFI ratios were correctly calculated in accordance with the Determination and the IM Determination, including for successive interruptions using the "multi-count approach"; • obtaining explanations for all significant variances to forecast; and • testing the accuracy of the number of connections to the Electricity Authority's register. 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 ISAE (NZ) 3000 (Revised) and SAE 3100 (Revised), to obtain reasonable assurance about whether the company has complied, in all material respects, with the Disclosure Information (which includes the Related Party Transaction Information) required to be audited by the Determination.

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

Inherent limitations

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

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

Restricted use

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

Independence and quality control

We complied with the Auditor-General's:

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

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

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

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

Chantelle Gernetzky
Audit New Zealand
On behalf of the Auditor-General
Christchurch, New Zealand
29 August 2024