COMMERCE COMMISSION NEW ZEALAND

EDB Information Disclosure Requirements
Information Templates

Schedules 1–10
excluding 5f–5h

Company Name	Network Tasman Limited
Disclosure Date	31 August 2024
Disclosure Year (year ended)	31 March 2024

Templates for Schedules 1–10 excluding 5f–5h
Prepared 16 February 2024

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Company Name	**Network Tasman 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)	MVA of capacity from EDB-owned distribution transformers ($/MVA)
Operational expenditure	23,290	354	113,503	4,054	31,798
Network	12,858	195	62,660	2,238	17,555
Non-network	10,433	158	50,842	1,816	14,244
Expenditure on assets	22,459	341	109,453	3,910	30,664
Network	21,996	334	107,196	3,829	30,032
Non-network	463	7	2,257	81	632

1(ii): Revenue metrics

	Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
Total consumer line charge revenue	59,887	909
Standard consumer line charge revenue	64,065	825
Non-standard consumer line charge revenue	36,597	516,754

1(iii): Service intensity measures

Demand density - See schedule 15 for corrected calculation.	41	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
Volume density	174	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
Connection point density	11	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
Energy intensity	15,179	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*

1(iv): Composition of regulatory income

	($000)	% of revenue
Operational expenditure	15,136	39.55%
Pass-through and recoverable costs excluding financial incentives and wash-ups	10,833	28.31%
Total depreciation	6,754	17.65%
Total revaluations	8,402	21.96%
Regulatory tax allowance	1,610	4.21%
Regulatory profit/(loss) including financial incentives and wash-ups	12,336	32.24%
Total regulatory income	38,266	

1(v): Reliability

Interruption rate	9.13	*Interruptions per 100 circuit km*

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2024**

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).
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		CY-2	CY-1	Current Year CY
7	**2(i): Return on Investment**			
8	for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
9	**ROI – comparable to a post tax WACC**	**%**	**%**	**%**
10	Reflecting all revenue earned	8.30%	7.77%	5.17%
11	Excluding revenue earned from financial incentives	8.30%	7.55%	4.89%
12	Excluding revenue earned from financial incentives and wash-ups	8.39%	7.63%	4.97%
13				
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	8.60%	8.29%	5.88%
21	Excluding revenue earned from financial incentives	8.60%	8.06%	5.59%
22	Excluding revenue earned from financial incentives and wash-ups	8.69%	8.15%	5.67%
23				
24	**WACC rate used to set regulatory price path**	4.57%	4.57%	4.57%
25				
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%
29				

30	**2(ii): Information Supporting the ROI**			**($000)**	
31					
32		Total opening RAB value	209,789		
33	*plus*	Opening deferred tax	(4,577)		
34	**Opening RIV**			205,212	
36	**Line charge revenue**			38,920	
38		Expenses cash outflow	25,969		
39	*add*	Assets commissioned	16,257		
40	*less*	Asset disposals	2,275		
41	*add*	Tax payments	535		
42	*less*	Other regulated income	(654)		
43	**Mid-year net cash outflows**			41,140	
44					
45	**Term credit spread differential allowance**			–	
47		Total closing RAB value	225,439		
48	*less*	Adjustment resulting from asset allocation	20		
49	*less*	Lost and found assets adjustment	–		
50	*plus*	Closing deferred tax	(5,651)		
51	**Closing RIV**			219,768	
53	**ROI – comparable to a vanilla WACC**				5.88%
55		Leverage (%)			42%
56		Cost of debt assumption (%)			5.97%
57		Corporate tax rate (%)			28%
59	**ROI – comparable to a post tax WACC**				5.17%

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2024**

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).

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

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

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

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

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

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

sch ref		
94	**Year-end ROI – comparable to a vanilla WACC**	5.51%
96	**Year-end ROI – comparable to a post tax WACC**	4.81%

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

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

sch ref			
102	IRIS incentive adjustment	736	
103	Purchased assets – avoided transmission charge	–	
104	Energy efficiency and demand incentive allowance		
105	Quality incentive adjustment	73	
106	Other financial incentives	–	
107	**Financial incentives**		810
109	**Impact of financial incentives on ROI**		0.28%
111	Input methodology claw-back	–	
112	CPP application recoverable costs	–	
113	Catastrophic event allowance	–	
114	Capex wash-up adjustment	(225)	
115	Transmission asset wash-up adjustment	–	
116	2013–15 NPV wash-up allowance	–	
117	Reconsideration event allowance	–	
118	Other wash-ups	–	
119	**Wash-up costs**		(225)
121	**Impact of wash-up costs on ROI**		–0.08%

Company Name	**Network Tasman 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		38,920
10	*plus*	Gains / (losses) on asset disposals		(871)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)		217
12				
13		**Total regulatory income**		38,266
14		**Expenses**		
15	*less*	Operational expenditure		15,136
16				
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups		10,833
18				
19		**Operating surplus / (deficit)**		12,297
20				
21	*less*	Total depreciation		6,754
22				
23	*plus*	Total revaluations		8,402
24				
25		**Regulatory profit / (loss) before tax**		13,945
26				
27	*less*	Term credit spread differential allowance		–
28				
29	*less*	Regulatory tax allowance		1,610
30				
31		**Regulatory profit/(loss) including financial incentives and wash-ups**		12,336
32				
33	**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**		**($000)**	
34		**Pass through costs**		
35		Rates	190	
36		Commerce Act levies	132	
37		Industry levies	136	
38		CPP specified pass through costs	–	
39		**Recoverable costs excluding financial incentives and wash-ups**		
40		Electricity lines service charge payable to Transpower	9,262	
41		Transpower new investment contract charges	1,113	
42		System operator services	–	
43		Distributed generation allowance	–	
44		Extended reserves allowance	–	
45		Other recoverable costs excluding financial incentives and wash-ups	–	
46		**Pass-through and recoverable costs excluding financial incentives and wash-ups**		10,833
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		–

Company Name	Network Tasman Limited
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SCHEDULE 4: REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)

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

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

sch ref

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

sch ref			RAB	RAB	RAB	RAB	RAB
8		for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
9			($000)	($000)	($000)	($000)	($000)
10		**Total opening RAB value**	165,472	174,395	177,306	191,545	209,789
12	*less*	**Total depreciation**	6,984	6,984	7,346	7,189	6,754
14	*plus*	**Total revaluations**	4,187	2,650	12,221	12,699	8,402
16	*plus*	**Assets commissioned**	12,075	8,066	10,506	13,863	16,257
18	*less*	**Asset disposals**	332	847	1,050	1,120	2,275
20	*plus*	**Lost and found assets adjustment**	–	–	–	–	–
22	*plus*	**Adjustment resulting from asset allocation**	(23)	26	(92)	(9)	20
24		**Total closing RAB value**	174,395	177,306	191,545	209,789	225,439

4(ii): Unallocated Regulatory Asset Base

sch ref			Unallocated RAB *		RAB	
28			($000)	($000)	($000)	($000)
29		**Total opening RAB value**		211,583		209,789
30	*less*					
31		**Total depreciation**		6,956		6,754
32	*plus*					
33		**Total revaluations**		8,474		8,402
34	*plus*					
35		Assets commissioned (other than below)	16,316		16,257	
36		Assets acquired from a regulated supplier	–		–	
37		Assets acquired from a related party	–		–	
38		**Assets commissioned**		16,316		16,257
39	*less*					
40		Asset disposals (other than below)	2,289		2,275	
41		Asset disposals to a regulated supplier	–		–	
42		Asset disposals to a related party	–		–	
43		**Asset disposals**		2,289		2,275
45	*plus*	**Lost and found assets adjustment**		–		–
47	*plus*	**Adjustment resulting from asset allocation**				20
49		**Total closing RAB value**		227,128		225,439

50 ** The 'unallocated RAB' is the total value of those assets used wholly or partially to provide electricity distribution services without any allowance being made for the allocation of costs to services provided by the supplier that are not electricity distribution services. The RAB value represents the value of these assets after applying this cost allocation. Neither value includes works under construction.*

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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

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	211,583		209,789	
61	*less*	Opening value of fully depreciated, disposed and lost assets	941		934	
62						
63		Total opening RAB value subject to revaluation	210,642		208,855	
64		**Total revaluations**		8,474		8,402
65						
66	**4(iv): Roll Forward of Works Under Construction**					
67			**Unallocated works under construction**		**Allocated works under construction**	
68		**Works under construction—preceding disclosure year**		9,527		9,570
69	*plus*	Capital expenditure	15,016		15,016	
70	*less*	Assets commissioned	16,316		16,257	
71	*plus*	Adjustment resulting from asset allocation			(53)	
72		**Works under construction - current disclosure year**		8,227		8,276
73						
74		Highest rate of capitalised finance applied				–
75						

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

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

EDBs must provide explanatory comment on the value of their RAB in Schedule 14 (Mandatory Explanatory Notes). This information is part of audited disclosure information (as defined in section 1.4 of 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	6,511		6,391	
80	Depreciation - no standard life assets	445		363	
81	Depreciation - modified life assets	–		–	
82	Depreciation - alternative depreciation in accordance with CPP	–		–	
83	**Total depreciation**		6,956		6,754

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**	8,997	12,040	31,388	30,976	67,097	31,170	11,329	13,349	3,443	209,789
100	*less*	Total depreciation	298	275	(62)	1,821	1,546	1,236	524	787	329	6,754
101	*plus*	Total revaluations	362	484	1,249	1,243	2,699	1,238	455	536	136	8,402
102	*plus*	Assets commissioned	494	186	2,729	4,446	1,422	3,377	3,047	390	166	16,257
103	*less*	Asset disposals	81	–	1,320	245	160	338	15	75	41	2,275
104	*plus*	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
105	*plus*	Adjustment resulting from asset allocation	–	–	–	(11)	–	–	–	(2)	33	20
106	*plus*	Asset category transfers	–	–	–	–	–	–	–	–	–	–
107		**Total closing RAB value**	9,474	12,435	34,108	34,588	69,512	34,211	14,292	13,411	3,408	225,439
109		**Asset Life**										
110		Weighted average remaining asset life	37.1	44.0	31.1	46.3	43.5	38.5	31.5	15.7	22.7	(years)
111		Weighted average expected total asset life	56.4	55.6	42.3	58.6	60.3	52.2	40.9	32.3	31.0	(years)

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SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

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

sch ref				($000)	
7		**5a(i): Regulatory Tax Allowance**		($000)	
8		**Regulatory profit / (loss) before tax**		13,945	
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	55		*
12		Amortisation of initial differences in asset values	3,236		
13		Amortisation of revaluations	1,913		
14				5,204	
16	*less*	Total revaluations	8,402		
17		Income included in regulatory profit / (loss) before tax but not taxable	–		*
18		Discretionary discounts and customer rebates	–		
19		Expenditure or loss deductible but not in regulatory profit / (loss) before tax	–		*
20		Notional deductible interest	4,998		
21				13,401	
23		**Regulatory taxable income**		5,748	
25	*less*	Utilised tax losses	–		
26		Regulatory net taxable income		5,748	
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**		1,610	
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)	
36		Opening unamortised initial differences in asset values	65,873		
37	*less*	Amortisation of initial differences in asset values	3,236		
38	*plus*	Adjustment for unamortised initial differences in assets acquired	–		
39	*less*	Adjustment for unamortised initial differences in assets disposed	62		
40		Closing unamortised initial differences in asset values		62,575	
42		Opening weighted average remaining useful life of relevant assets (years)		20	
43					
44		**5a(iv): Amortisation of Revaluations**		($000)	
46		Opening sum of RAB values without revaluations	166,965		
48		Adjusted depreciation	4,841		
49		Total depreciation	6,754		
50		Amortisation of revaluations		1,913	

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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				
52		**5a(v): Reconciliation of Tax Losses**		**($000)**
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)**
60		**Opening deferred tax**	(4,577)	
62	*plus*	Tax effect of adjusted depreciation	1,355	
64	*less*	Tax effect of tax depreciation	1,972	
66	*plus*	Tax effect of other temporary differences*	(169)	
68	*less*	Tax effect of amortisation of initial differences in asset values	906	
70	*plus*	Deferred tax balance relating to assets acquired in the disclosure year	–	
72	*less*	Deferred tax balance relating to assets disposed in the disclosure year	(599)	
74	*plus*	Deferred tax cost allocation adjustment	18	
75				
76		**Closing deferred tax**		(5,651)
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**	83,893	
84	*less*	Tax depreciation	7,042	
85	*plus*	Regulatory tax asset value of assets commissioned	16,243	
86	*less*	Regulatory tax asset value of asset disposals	134	
87	*plus*	Lost and found assets adjustment	–	
88	*plus*	Adjustment resulting from asset allocation	83	
89	*plus*	Other adjustments to the RAB tax value	–	
90		**Closing sum of regulatory tax asset values**		93,043

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SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

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

sch ref				
7	**5b(i): Summary—Related Party Transactions**	**($000)**	**($000)**	
8	**Total regulatory income**		80	
9				
10	**Market value of asset disposals**		–	
11				
12	Service interruptions and emergencies	–		
13	Vegetation management	–		
14	Routine and corrective maintenance and inspection	–		
15	Asset replacement and renewal (opex)	–		
16	**Network opex**		–	
17	Business support	–		
18	System operations and network support - other	–		
19	Non-network solutions provided by a related party or third party (Not Required befo	–		*Not Required before DY2025*
20	**Operational expenditure**		–	
21	Consumer connection	–		
22	System growth	–		
23	Asset replacement and renewal (capex)	–		
24	Asset relocations	–		
25	Quality of supply	–		
26	Legislative and regulatory	–		
27	Other reliability, safety and environment	–		
28	**Expenditure on non-network assets**		–	
29	**Expenditure on assets**		–	
30	Cost of financing		–	
31	Value of capital contributions		–	
32	Value of vested assets		–	
33	**Capital Expenditure**		–	
34	**Total expenditure**		–	
35				
36	**Other related party transactions**		–	

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)
37			
38			
39		[Select one]	
40		[Select one]	
41		[Select one]	
42		[Select one]	
43		[Select one]	
44		[Select one]	
45		[Select one]	
46		[Select one]	
47		[Select one]	
48		[Select one]	
49		[Select one]	
50		[Select one]	
51		[Select one]	
52		[Select one]	
53		[Select one]	
54	**Total value of related party transactions**		–
55	** include additional rows if needed*		

Company Name	**Network Tasman 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
11	n/a								
12									
13									
14									
15									
16	* include additional rows if needed						–	–	–

17

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

19

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

Company Name	**Network Tasman 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(i): Operating Cost Allocations

sch ref		Arm's length deduction	Value allocated ($000s) Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
10	**Service interruptions and emergencies**					
11	Directly attributable		1,355			
12	Not directly attributable	–	–	–	–	–
13	**Total attributable to regulated service**		1,355			
14	**Vegetation management**					
15	Directly attributable		1,572			
16	Not directly attributable	–	–	–	–	–
17	**Total attributable to regulated service**		1,572			
18	**Routine and corrective maintenance and inspection**					
19	Directly attributable		3,195			
20	Not directly attributable	–	–	–	–	–
21	**Total attributable to regulated service**		3,195			
22	**Asset replacement and renewal**					
23	Directly attributable		2,234			
24	Not directly attributable	–	–	–	–	–
25	**Total attributable to regulated service**		2,234			
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		3,911			
32	Not directly attributable	–	–	–	–	–
33	**Total attributable to regulated service**		3,911			
34	**Business support**					
35	Directly attributable		702			
36	Not directly attributable	–	2,168	1,211	3,379	–
37	**Total attributable to regulated service**		2,870			
38						
39	**Operating costs directly attributable**		12,969			
40	**Operating costs not directly attributable**	–	2,168	1,211	3,379	–
41	**Operational expenditure**		15,137			
42						

Company Name	**Network Tasman 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

sch ref		($000)
43	**5d(ii): Other Cost Allocations**	
44	**Pass through and recoverable costs**	**($000)**
45	**Pass through costs**	
46	Directly attributable	454
47	Not directly attributable	3
48	**Total attributable to regulated service**	457
49	**Recoverable costs**	
50	Directly attributable	10,375
51	Not directly attributable	–
52	**Total attributable to regulated service**	10,375
53		

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

sch ref				CY-1	Current Year (CY)
55				**($000)**	
56	**Change in cost allocation 1**			**CY-1**	**Current Year (CY)**
57	Cost category		Original allocation		
58	Original allocator or line items		New allocation		
59	New allocator or line items		Difference	–	–
60					
61	Rationale for change				
62					
63					
64				**($000)**	
65	**Change in cost allocation 2**			**CY-1**	**Current Year (CY)**
66	Cost category		Original allocation		
67	Original allocator or line items		New allocation		
68	New allocator or line items		Difference	–	–
69					
70	Rationale for change				
71					
72					
73				**($000)**	
74	**Change in cost allocation 3**			**CY-1**	**Current Year (CY)**
75	Cost category		Original allocation		
76	Original allocator or line items		New allocation		
77	New allocator or line items		Difference	–	–
78					
79	Rationale for change				
80					
81					

82 ** 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.*

83 *† include additional rows if needed*

Company Name	**Network Tasman 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

7 **5e(i): Regulated Service Asset Values**

sch ref		Value allocated ($000s) Electricity distribution services
10	**Subtransmission lines**	
11	Directly attributable	9,474
12	Not directly attributable	–
13	**Total attributable to regulated service**	9,474
14	**Subtransmission cables**	
15	Directly attributable	12,435
16	Not directly attributable	–
17	**Total attributable to regulated service**	12,435
18	**Zone substations**	
19	Directly attributable	34,108
20	Not directly attributable	–
21	**Total attributable to regulated service**	34,108
22	**Distribution and LV lines**	
23	Directly attributable	32,389
24	Not directly attributable	2,200
25	**Total attributable to regulated service**	34,589
26	**Distribution and LV cables**	
27	Directly attributable	69,512
28	Not directly attributable	–
29	**Total attributable to regulated service**	69,512
30	**Distribution substations and transformers**	
31	Directly attributable	34,211
32	Not directly attributable	–
33	**Total attributable to regulated service**	34,211
34	**Distribution switchgear**	
35	Directly attributable	14,292
36	Not directly attributable	–
37	**Total attributable to regulated service**	14,292
38	**Other network assets**	
39	Directly attributable	13,358
40	Not directly attributable	51
41	**Total attributable to regulated service**	13,409
42	**Non-network assets**	
43	Directly attributable	1,055
44	Not directly attributable	2,354
45	**Total attributable to regulated service**	3,409
47	**Regulated service asset value directly attributable**	220,834
48	**Regulated service asset value not directly attributable**	4,605
49	**Total closing RAB value**	225,439

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

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

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

80 *† include additional rows if needed*

Company Name	**Network Tasman 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				
7		**6a(i): Expenditure on Assets**	**($000)**	**($000)**
8		Consumer connection		1,360
9		System growth		1,501
10		Asset replacement and renewal		6,217
11		Asset relocations		3
12		Reliability, safety and environment:		
13		Quality of supply	4,683	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	531	
16		**Total reliability, safety and environment**		5,214
17		**Expenditure on network assets**		14,295
18		Expenditure on non-network assets		301
19				
20		**Expenditure on assets**		14,596
21	*plus*	Cost of financing		–
22	*less*	Value of capital contributions		38
23	*plus*	Value of vested assets		458
24				
25		**Capital expenditure**		15,016
26		**6a(ii): Subcomponents of Expenditure on Assets (where known)**		**($000)**
27		Energy efficiency and demand side management, reduction of energy losses		27
28		Overhead to underground conversion		3
29		Research and development		–
30		**6a(iii): Consumer Connection**		
31		*Consumer types defined by EDB**	**($000)**	**($000)**
32		Consumers 20kVA and less	554	
33		Consumers greater than 20kVA	806	
34		-	–	
35		-	–	
36		-	–	
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		1,360
39				
40	*less*	Capital contributions funding consumer connection expenditure	–	
41		**Consumer connection less capital contributions**		1,360
42		**6a(iv): System Growth and Asset Replacement and Renewal**		**Asset Replacement and**
43			**System Growth**	**Renewal**
44			**($000)**	**($000)**
45		Subtransmission	–	94
46		Zone substations	30	3,429
47		Distribution and LV lines	427	305
48		Distribution and LV cables	529	765
49		Distribution substations and transformers	306	85
50		Distribution switchgear	51	102
51		Other network assets	158	1,437
52		**System growth and asset replacement and renewal expenditure**	1,501	6,217
53	*less*	Capital contributions funding system growth and asset replacement and renewal	21	17
54		**System growth and asset replacement and renewal less capital contributions**	1,480	6,200
55				
56		**6a(v): Asset Relocations**		
57		*Project or programme**	**($000)**	**($000)**
58		-	–	
59		-	–	
60		-	–	
61		-	–	
62		-	–	
63		** include additional rows if needed*		
64		All other projects or programmes - asset relocations	3	
65		**Asset relocations expenditure**		3
66	*less*	Capital contributions funding asset relocations	–	
67		**Asset relocations less capital contributions**		3

Company Name	**Network Tasman 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				
68				
69		**6a(vi): Quality of Supply**		
70		*Project or programme**	**($000)**	**($000)**
71		Pole improvements	375	
72		Feeder & interconnection cables or lines	4,102	
73		-	–	
74		-	–	
75		-	–	
76		** include additional rows if needed*		
77		All other projects programmes - quality of supply	206	
78		**Quality of supply expenditure**		4,683
79	*less*	Capital contributions funding quality of supply	–	
80		**Quality of supply less capital contributions**		4,683
81		**6a(vii): Legislative and Regulatory**		
82		*Project or programme**	**($000)**	**($000)**
83		-	–	
84		-	–	
85		-	–	
86		-	–	
87		-	–	
88		** include additional rows if needed*		
89		All other projects or programmes - legislative and regulatory	–	
90		**Legislative and regulatory expenditure**		–
91	*less*	Capital contributions funding legislative and regulatory	–	
92		**Legislative and regulatory less capital contributions**		–
93		**6a(viii): Other Reliability, Safety and Environment**		
94		*Project or programme**	**($000)**	**($000)**
95		Platform Transformer to Padmount	427	
96		–	–	
97		–	–	
98		–	–	
99		–	–	
100		** include additional rows if needed*		
101		All other projects or programmes - other reliability, safety and environment	104	
102		**Other reliability, safety and environment expenditure**		531
103	*less*	Capital contributions funding other reliability, safety and environment	–	
104		**Other reliability, safety and environment less capital contributions**		531
105				
106		**6a(ix): Non-Network Assets**		
107		**Routine expenditure**		
108		*Project or programme**	**($000)**	**($000)**
109		–	–	
110		–	–	
111		–	–	
112		–	–	
113		–	–	
114		** include additional rows if needed*		
115		All other projects or programmes - routine expenditure	301	
116		**Routine expenditure**		301
117		**Atypical expenditure**		
118		*Project or programme**	**($000)**	**($000)**
119		–	–	
120		–	–	
121		–	–	
122		–	–	
123		–	–	
124		** include additional rows if needed*		
125		All other projects or programmes - atypical expenditure	–	
126		**Atypical expenditure**		–
127				
128		**Expenditure on non-network assets**		301

	Company Name	Network Tasman 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	1,355	
9	Vegetation management	1,572	
10	Routine and corrective maintenance and inspection	3,195	
11	Asset replacement and renewal	2,234	
12	**Network opex**		8,356
13	Non-network solutions provided by *Required for DY2025 only*	–	
14	System operations and network support	3,911	
15	Business support	2,869	
16	**Non-network opex**		6,780
18	**Operational expenditure**		15,136
19	**6b(i): Operational Exp** *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**	–	
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	–	
37	**Non-network opex**		–
39	**Operational expenditure**		–
40	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
41	Energy efficiency and demand side management, reduction of energy losses		161
42	Direct billing*		–
43	Research and development		–
44	Insurance		471
45	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**Network Tasman 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				
7	**7(i): Revenue**	**Target ($000) [1]**	**Actual ($000)**	**% variance**
8	Line charge revenue	38,692	38,920	1%
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	1,175	1,360	16%
11	System growth	8,440	1,501	(82%)
12	Asset replacement and renewal	6,470	6,217	(4%)
13	Asset relocations	500	3	(99%)
14	Reliability, safety and environment:			
15	Quality of supply	3,845	4,683	22%
16	Legislative and regulatory	–	–	–
17	Other reliability, safety and environment	595	531	(11%)
18	**Total reliability, safety and environment**	4,440	5,214	17%
19	**Expenditure on network assets**	21,025	14,295	(32%)
20	Expenditure on non-network assets	2,510	301	(88%)
21	Expenditure on assets	23,535	14,596	(38%)
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	1,896	1,355	(29%)
24	Vegetation management	1,238	1,572	27%
25	Routine and corrective maintenance and inspection	2,434	3,195	31%
26	Asset replacement and renewal	2,001	2,234	12%
27	**Network opex**	7,569	8,356	10%
28	Non-network solutions provided by a related party or third party *Not Required before DY2025*	–	–	–
29	System operations and network support	3,760	3,911	4%
30	Business support	2,931	2,869	(2%)
31	**Non-network opex**	6,691	6,780	1%
32	**Operational expenditure**	14,260	15,136	6%
33	**7(iv): Subcomponents of Expenditure on Assets (where known)**			
34	Energy efficiency and demand side management, reduction of energy losses	–	3	–
35	Overhead to underground conversion	500	–	(100%)
36	Research and development	–	–	–
38	**7(v): Subcomponents of Operational Expenditure (where known)**			
39	Energy efficiency and demand side management, reduction of energy losses	117	161	38%
40	Direct billing	–	–	–
41	Research and development	–	–	–
42	Insurance	499	471	(6%)

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: **Network Tasman Limited**
For Year Ended: **31 March 2024**
Network / Sub-Network Name:

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**

11 **Billed quantities by price component** *Not Required after DY2024*

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	delivered to ICPs in disclosure year (MWh)	Price component	0STL	0UNM	1RLANY	1RLDAY	1RLDEF	1RLNIT	1RLOFP	1RLPEK	1RLWSR	1RLGEN	1RSANY
13						Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	Watts	day	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh
15	0S	Unmetered Streetlamps	Standard	–	1,840		438,050	–	–	–	–	–	–	–	–	–	–
16	0UNM	Unmetered Supplies	Standard	69	13		–	69	–	–	–	–	–	–	–	–	–
17	1RL	15 kVA Capacity	Standard	19,133	107,337		–	–	24,631	563	4,075	1,000	24,272	26,366	26,430	3,937	–
18	1RS	15 kVA Capacity	Standard	16,792	149,097		–	–	–	–	–	–	–	–	–	–	35,027
19	1GL	15 kVA Capacity	Standard	3,666	23,084		–	–	–	–	–	–	–	–	–	–	–
20	2	20 - 150 kVA Capacity	Standard	2,886	104,870		–	–	–	–	–	–	–	–	–	–	–
21	2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	–	29		–	–	–	–	–	–	–	–	–	–	–
22	2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	62	473		–	–	–	–	–	–	–	–	–	–	–
23	HLF	High Load Factor, 15-150kVA Capacity	Standard	4	6,796		–	–	–	–	–	–	–	–	–	–	–
24	3.1	Between 150 and 3000kVA	Standard	4	8,351		–	–	–	–	–	–	–	–	–	–	–
25	3.3	Between 150 and 3000kVA	Standard	6	8,711		–	–	–	–	–	–	–	–	–	–	–
26	3.4	Between 150 and 3000kVA	Standard	185	129,615		–	–	–	–	–	–	–	–	–	–	–
27	3.5	Between 150 and 3000kVA	Standard	2	10,831		–	–	–	–	–	–	–	–	–	–	–
28	6.1	> 3000,	Non-standard	1	86,733		–	–	–	–	–	–	–	–	–	–	–
29	6.2	> 3000,	Non-standard	1	12,021		–	–	–	–	–	–	–	–	–	–	–
30	CB	Cobb River Hydro	Non-standard	1	86		–	–	–	–	–	–	–	–	–	–	–
31	Hydro	MAT, CB, EG etc	Non-standard	4	–		–	–	–	–	–	–	–	–	–	–	–
32	Connections	0	Standard	–	–		–	–	–	–	–	–	–	–	–	–	–
33	Solar Connections	0	Standard	–	–		–	–	–	–	–	–	–	–	–	–	–
35	*Add extra rows for additional consumer groups or price category codes as necessary*																
36			**Standard consumer totals**	42,809	551,047		438,050	69	24,631	563	4,075	1,000	24,272	26,366	26,430	3,937	35,027
37			**Non-standard consumer totals**	7	98,840		–	–	–	–	–	–	–	–	–	–	–
38			**Total for all consumers**	42,816	649,887		438,050	69	24,631	563	4,075	1,000	24,272	26,366	26,430	3,937	35,027

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2024**
Network / Sub-Network Name	

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	delivered to ICPs in disclosure year (MWh)	1RSDAY	1RSDEF	1RSNIT	1RSOFP	1RSPEK	1RSWSR	1RSGEN	1GLANY	1GLDAY	1GLDEF	1GLNIT
12					Price component	1RSDAY	1RSDEF	1RSNIT	1RSOFP	1RSPEK	1RSWSR	1RSGEN	1GLANY	1GLDAY	1GLDEF	1GLNIT
13					Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh
15	0S	Unmetered Streetlamps	Standard	–	1,840	–	–	–	–	–	–	–	–	–	–	–
16	0UNM	Unmetered Supplies	Standard	69	13	–	–	–	–	–	–	–	–	–	–	–
17	1RL	15 kVA Capacity	Standard	19,133	107,337	–	–	–	–	–	–	–	–	–	–	–
18	1RS	15 kVA Capacity	Standard	16,792	149,097	1,106	6,010	1,626	34,742	37,320	33,266	3,097	–	–	–	–
19	1GL	15 kVA Capacity	Standard	3,666	23,084	–	–	–	–	–	–	–	4,917	389	2,737	289
20	2	20 - 150 kVA Capacity	Standard	2,886	104,870	–	–	–	–	–	–	–	–	–	–	–
21	2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	–	29	–	–	–	–	–	–	–	–	–	–	–
22	2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	62	473	–	–	–	–	–	–	–	–	–	–	–
23	HLF	High Load Factor, 15-150kVA Capacity	Standard	4	6,796	–	–	–	–	–	–	–	–	–	–	–
24	3.1	Between 150 and 3000kVA	Standard	4	8,351	–	–	–	–	–	–	–	–	–	–	–
25	3.3	Between 150 and 3000kVA	Standard	6	8,711	–	–	–	–	–	–	–	–	–	–	–
26	3.4	Between 150 and 3000kVA	Standard	185	129,615	–	–	–	–	–	–	–	–	–	–	–
27	3.5	Between 150 and 3000kVA	Standard	2	10,831	–	–	–	–	–	–	–	–	–	–	–
28	6.1	> 3000,	Non-standard	1	86,733	–	–	–	–	–	–	–	–	–	–	–
29	6.2	> 3000,	Non-standard	1	12,021	–	–	–	–	–	–	–	–	–	–	–
30	CB	Cobb River Hydro	Non-standard	1	86	–	–	–	–	–	–	–	–	–	–	–
31	Hydro	MAT, CB, EG etc	Non-standard	4	–	–	–	–	–	–	–	–	–	–	–	–
32	Connections	0	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
33	Solar Connections	0	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
35	*Add extra rows for additional consumer groups or price category codes as necessary*															
36			**Standard consumer totals**	42,809	551,047	1,106	6,010	1,626	34,742	37,320	33,266	3,097	4,917	389	2,737	289
37			**Non-standard consumer totals**	7	98,840	–	–	–	–	–	–	–	–	–	–	–
38			**Total for all consumers**	42,816	649,887	1,106	6,010	1,626	34,742	37,320	33,266	3,097	4,917	389	2,737	289

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2024**
Network / Sub-Network Name	

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	delivered to ICPs in disclosure year (MWh)	1GLOFP	1GLPEK	1GLWSR	1GLGEN	2ANY	2DAY	2DEF	2NIT	2OFP	2PEK	2WSR
12					Price component	1GLOFP	1GLPEK	1GLWSR	1GLGEN	2ANY	2DAY	2DEF	2NIT	2OFP	2PEK	2WSR
13					Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh
15	0S	Unmetered Streetlamps	Standard	–	1,840	–	–	–	–	–	–	–	–	–	–	–
16	0UNM	Unmetered Supplies	Standard	69	13	–	–	–	–	–	–	–	–	–	–	–
17	1RL	15 kVA Capacity	Standard	19,133	107,337	–	–	–	–	–	–	–	–	–	–	–
18	1RS	15 kVA Capacity	Standard	16,792	149,097	–	–	–	–	–	–	–	–	–	–	–
19	1GL	15 kVA Capacity	Standard	3,666	23,084	5,872	7,344	1,536	2,541	–	–	–	–	–	–	–
20	2	20 - 150 kVA Capacity	Standard	2,886	104,870	–	–	–	–	21,748	11,074	15,016	4,764	20,826	28,539	2,903
21	2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	–	29	–	–	–	–	–	–	–	–	–	–	–
22	2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	62	473	–	–	–	–	–	–	–	–	–	–	–
23	HLF	High Load Factor, 15-150kVA Capacity	Standard	4	6,796	–	–	–	–	–	–	–	–	–	–	–
24	3.1	Between 150 and 3000kVA	Standard	4	8,351	–	–	–	–	–	–	–	–	–	–	–
25	3.3	Between 150 and 3000kVA	Standard	6	8,711	–	–	–	–	–	–	–	–	–	–	–
26	3.4	Between 150 and 3000kVA	Standard	185	129,615	–	–	–	–	–	–	–	–	–	–	–
27	3.5	Between 150 and 3000kVA	Standard	2	10,831	–	–	–	–	–	–	–	–	–	–	–
28	6.1	> 3000,	Non-standard	1	86,733	–	–	–	–	–	–	–	–	–	–	–
29	6.2	> 3000,	Non-standard	1	12,021	–	–	–	–	–	–	–	–	–	–	–
30	CB	Cobb River Hydro	Non-standard	1	86	–	–	–	–	–	–	–	–	–	–	–
31	Hydro	MAT, CB, EG etc	Non-standard	4	–	–	–	–	–	–	–	–	–	–	–	–
32	Connections	0	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
33	Solar Connections	0	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
35	*Add extra rows for additional consumer groups or price category codes as necessary*															
36			**Standard consumer totals**	42,809	551,047	5,872	7,344	1,536	2,541	21,748	11,074	15,016	4,764	20,826	28,539	2,903
37			**Non-standard consumer totals**	7	98,840	–	–	–	–	–	–	–	–	–	–	–
38			**Total for all consumers**	42,816	649,887	5,872	7,344	1,536	2,541	21,748	11,074	15,016	4,764	20,826	28,539	2,903

Company Name **Network Tasman Limited**
For Year Ended **31 March 2024**
Network / Sub-Network Name

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	delivered to ICPs in disclosure year (MWh)												
12						**Price component**	2GEN	2LANY	2LDAY	2LDEF	2LNIT	2LOFP	2LPEK	2LWSR	2LGEN	2HANY	2HDAY
13						**Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)**	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh
15	0S	Unmetered Streetlamps	Standard	–	1,840		–	–	–	–	–	–	–	–	–	–	–
16	0UNM	Unmetered Supplies	Standard	69	13		–	–	–	–	–	–	–	–	–	–	–
17	1RL	15 kVA Capacity	Standard	19,133	107,337		–	–	–	–	–	–	–	–	–	–	–
18	1RS	15 kVA Capacity	Standard	16,792	149,097		–	–	–	–	–	–	–	–	–	–	–
19	1GL	15 kVA Capacity	Standard	3,666	23,084		–	–	–	–	–	–	–	–	–	–	–
20	2	20 - 150 kVA Capacity	Standard	2,886	104,870		1,201	–	–	–	–	–	–	–	–	–	–
21	2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	–	29		–	–	–	–	–	–	–	–	–	6	–
22	2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	62	473		–	218	20	25	11	65	77	57	14	–	–
23	HLF	High Load Factor, 15-150kVA Capacity	Standard	4	6,796		–	–	–	–	–	–	–	–	–	–	–
24	3.1	Between 150 and 3000kVA	Standard	4	8,351		–	–	–	–	–	–	–	–	–	–	–
25	3.3	Between 150 and 3000kVA	Standard	6	8,711		–	–	–	–	–	–	–	–	–	–	–
26	3.4	Between 150 and 3000kVA	Standard	185	129,615		–	–	–	–	–	–	–	–	–	–	–
27	3.5	Between 150 and 3000kVA	Standard	2	10,831		–	–	–	–	–	–	–	–	–	–	–
28	6.1	> 3000,	Non-standard	1	86,733		–	–	–	–	–	–	–	–	–	–	–
29	6.2	> 3000,	Non-standard	1	12,021		–	–	–	–	–	–	–	–	–	–	–
30	CB	Cobb River Hydro	Non-standard	1	86		–	–	–	–	–	–	–	–	–	–	–
31	Hydro	MAT, CB, EG etc	Non-standard	4	–		–	–	–	–	–	–	–	–	–	–	–
32	Connections	0	Standard	–	–		–	–	–	–	–	–	–	–	–	–	–
33	Solar Connections	0	Standard	–	–		–	–	–	–	–	–	–	–	–	–	–
34																	
35	*Add extra rows for additional consumer groups or price category codes as necessary*																
36			**Standard consumer totals**	42,809	551,047		1,201	218	20	25	11	65	77	57	14	6	–
37			**Non-standard consumer totals**	7	98,840		–	–	–	–	–	–	–	–	–	–	–
38			**Total for all consumers**	42,816	649,887		1,201	218	20	25	11	65	77	57	14	6	–

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2024**
Network / Sub-Network Name	

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.

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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	delivered to ICPs in disclosure year (MWh)	Price component	2HDEF	2HNIT	2HOFP	2HPEK	2HWSR	2HGEN	HLFANY	HLFDAY	HLFDEF	HLFNIT	HLFOFP
13						Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh
15	0S	Unmetered Streetlamps	Standard	–	1,840		–	–	–	–	–	–	–	–	–	–	–
16	0UNM	Unmetered Supplies	Standard	69	13		–	–	–	–	–	–	–	–	–	–	–
17	1RL	15 kVA Capacity	Standard	19,133	107,337		–	–	–	–	–	–	–	–	–	–	–
18	1RS	15 kVA Capacity	Standard	16,792	149,097		–	–	–	–	–	–	–	–	–	–	–
19	1GL	15 kVA Capacity	Standard	3,666	23,084		–	–	–	–	–	–	–	–	–	–	–
20	2	20 - 150 kVA Capacity	Standard	2,886	104,870		–	–	–	–	–	–	–	–	–	–	–
21	2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	–	29		–	–	9	9	5	–	–	–	–	–	–
22	2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	62	473		–	–	–	–	–	–	–	–	–	–	–
23	HLF	High Load Factor, 15-150kVA Capacity	Standard	4	6,796		–	–	–	–	–	–	401	191	782	73	2,419
24	3.1	Between 150 and 3000kVA	Standard	4	8,351		–	–	–	–	–	–	–	–	–	–	–
25	3.3	Between 150 and 3000kVA	Standard	6	8,711		–	–	–	–	–	–	–	–	–	–	–
26	3.4	Between 150 and 3000kVA	Standard	185	129,615		–	–	–	–	–	–	–	–	–	–	–
27	3.5	Between 150 and 3000kVA	Standard	2	10,831		–	–	–	–	–	–	–	–	–	–	–
28	6.1	> 3000,	Non-standard	1	86,733		–	–	–	–	–	–	–	–	–	–	–
29	6.2	> 3000,	Non-standard	1	12,021		–	–	–	–	–	–	–	–	–	–	–
30	CB	Cobb River Hydro	Non-standard	1	86		–	–	–	–	–	–	–	–	–	–	–
31	Hydro	MAT, CB, EG etc	Non-standard	4	–		–	–	–	–	–	–	–	–	–	–	–
32	Connections	0	Standard	–	–		–	–	–	–	–	–	–	–	–	–	–
33	Solar Connections	0	Standard	–	–		–	–	–	–	–	–	–	–	–	–	–
35	*Add extra rows for additional consumer groups or price category codes as necessary*																
36			**Standard consumer totals**	42,809	551,047		–	–	9	9	5	–	401	191	782	73	2,419
37			**Non-standard consumer totals**	7	98,840		–	–	–	–	–	–	–	–	–	–	–
38			**Total for all consumers**	42,816	649,887		–	–	9	9	5	–	401	191	782	73	2,419

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2024**
Network / Sub-Network Name	

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.

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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	delivered to ICPs in disclosure year (MWh)		HLFPEK	HLFWSR	HLFGEN	1RL	1RS	1GL	2	2HLFC	2LLFC	HLF	AnyDem3 1
12						**Price component**	HLFPEK	HLFWSR	HLFGEN	1RL	1RS	1GL	2	2HLFC	2LLFC	HLF	AnyDem3 1
13						**Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)**	kWh	kWh	kWh	Daily	Daily	Daily	Capacity	Daily	Daily	kVA	kVA
15	0S	Unmetered Streetlamps	Standard	–	1,840		–	–	–	–	–	–	–	–	–	–	–
16	0UNM	Unmetered Supplies	Standard	69	13		–	–	–	–	–	–	–	–	–	–	–
17	1RL	15 kVA Capacity	Standard	19,133	107,337		–	–	–	19,288	–	–	–	–	–	–	–
18	1RS	15 kVA Capacity	Standard	16,792	149,097		–	–	–	–	16,737	–	–	–	–	–	–
19	1GL	15 kVA Capacity	Standard	3,666	23,084		–	–	–	–	–	3,722	–	–	–	–	–
20	2	20 - 150 kVA Capacity	Standard	2,886	104,870		–	–	–	–	–	–	133,105	–	–	–	–
21	2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	–	29		–	–	–	–	–	–	–	8	–	–	–
22	2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	62	473		–	–	–	–	–	–	–	–	72	–	–
23	HLF	High Load Factor, 15-150kVA Capacity	Standard	4	6,796		2,878	52	23	–	–	–	–	–	–	2,716	–
24	3.1	Between 150 and 3000kVA	Standard	4	8,351		–	–	–	–	–	–	–	–	–	–	2,066
25	3.3	Between 150 and 3000kVA	Standard	6	8,711		–	–	–	–	–	–	–	–	–	–	–
26	3.4	Between 150 and 3000kVA	Standard	185	129,615		–	–	–	–	–	–	–	–	–	–	–
27	3.5	Between 150 and 3000kVA	Standard	2	10,831		–	–	–	–	–	–	–	–	–	–	–
28	6.1	> 3000,	Non-standard	1	86,733		–	–	–	–	–	–	–	–	–	–	–
29	6.2	> 3000,	Non-standard	1	12,021		–	–	–	–	–	–	–	–	–	–	–
30	CB	Cobb River Hydro	Non-standard	1	86		–	–	–	–	–	–	–	–	–	–	–
31	Hydro	MAT, CB, EG etc	Non-standard	4	–		–	–	–	–	–	–	–	–	–	–	–
32	Connections	0	Standard	–	–		–	–	–	–	–	–	–	–	–	–	–
33	Solar Connections	0	Standard	–	–		–	–	–	–	–	–	–	–	–	–	–
35	*Add extra rows for additional consumer groups or price category codes as necessary*																
36			**Standard consumer totals**	42,809	551,047		2,878	52	23	19,288	16,737	3,722	133,105	8	72	2,716	2,066
37			**Non-standard consumer totals**	7	98,840		–	–	–	–	–	–	–	–	–	–	–
38			**Total for all consumers**	42,816	649,887		2,878	52	23	19,288	16,737	3,722	133,105	8	72	2,716	2,066

Company Name **Network Tasman Limited**

For Year Ended **31 March 2024**

Network / Sub-Network Name

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.

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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)	AnyDem33	AnyDem34	AnyDem35	Any_t	kVAr	SD31	SN31	WD31	WN31	SD33	SN33
13					Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	kVA	kVA	kVA	kW	kVAr	kWh	kWh	kWh	kWh	kWh	kWh
15	0S	Unmetered Streetlamps	Standard	–	1,840	–	–	–	–	–	–	–	–	–	–	–
16	0UNM	Unmetered Supplies	Standard	69	13	–	–	–	–	–	–	–	–	–	–	–
17	1RL	15 kVA Capacity	Standard	19,133	107,337	–	–	–	–	–	–	–	–	–	–	–
18	1RS	15 kVA Capacity	Standard	16,792	149,097	–	–	–	–	–	–	–	–	–	–	–
19	1GL	15 kVA Capacity	Standard	3,666	23,084	–	–	–	–	–	–	–	–	–	–	–
20	2	20 - 150 kVA Capacity	Standard	2,886	104,870	–	–	–	–	–	–	–	–	–	–	–
21	2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	–	29	–	–	–	–	–	–	–	–	–	–	–
22	2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	62	473	–	–	–	–	–	–	–	–	–	–	–
23	HLF	High Load Factor, 15-150kVA Capacity	Standard	4	6,796	–	–	–	–	–	–	–	–	–	–	–
24	3.1	Between 150 and 3000kVA	Standard	4	8,351	–	–	–	2,065	–	3,374	1,412	2,532	1,033	–	–
25	3.3	Between 150 and 3000kVA	Standard	6	8,711	2,506	–	–	2,278	–	–	–	–	–	3,788	1,758
26	3.4	Between 150 and 3000kVA	Standard	185	129,615	–	52,343	–	47,124	93	–	–	–	–	–	–
27	3.5	Between 150 and 3000kVA	Standard	2	10,831	–	–	3,047	3,045	–	–	–	–	–	–	–
28	6.1	> 3000,	Non-standard	1	86,733	–	–	–	–	–	–	–	–	–	–	–
29	6.2	> 3000,	Non-standard	1	12,021	–	–	–	–	–	–	–	–	–	–	–
30	CB	Cobb River Hydro	Non-standard	1	86	–	–	–	–	–	–	–	–	–	–	–
31	Hydro	MAT, CB, EG etc	Non-standard	4	–	–	–	–	–	–	–	–	–	–	–	–
32	Connections	0	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
33	Solar Connections	0	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
35	*Add extra rows for additional consumer groups or price category codes as necessary*															
36			**Standard consumer totals**	42,809	551,047	2,506	52,343	3,047	54,512	93	3,374	1,412	2,532	1,033	3,788	1,758
37			**Non-standard consumer totals**	7	98,840	–	–	–	–	–	–	–	–	–	–	–
38			**Total for all consumers**	42,816	649,887	2,506	52,343	3,047	54,512	93	3,374	1,412	2,532	1,033	3,788	1,758

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2024**
Network / Sub-Network Name	

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	delivered to ICPs in disclosure year (MWh)	Price component	WD33	WN33	SD34	SN34	WD34	WN34	SD35	SN35	WD35	WN35	3.1GEN
13						Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh
15	0S	Unmetered Streetlamps	Standard	–	1,840		–	–	–	–	–	–	–	–	–	–	–
16	0UNM	Unmetered Supplies	Standard	69	13		–	–	–	–	–	–	–	–	–	–	–
17	1RL	15 kVA Capacity	Standard	19,133	107,337		–	–	–	–	–	–	–	–	–	–	–
18	1RS	15 kVA Capacity	Standard	16,792	149,097		–	–	–	–	–	–	–	–	–	–	–
19	1GL	15 kVA Capacity	Standard	3,666	23,084		–	–	–	–	–	–	–	–	–	–	–
20	2	20 - 150 kVA Capacity	Standard	2,886	104,870		–	–	–	–	–	–	–	–	–	–	–
21	2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	–	29		–	–	–	–	–	–	–	–	–	–	–
22	2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	62	473		–	–	–	–	–	–	–	–	–	–	–
23	HLF	High Load Factor, 15-150kVA Capacity	Standard	4	6,796		–	–	–	–	–	–	–	–	–	–	–
24	3.1	Between 150 and 3000kVA	Standard	4	8,351		–	–	–	–	–	–	–	–	–	–	–
25	3.3	Between 150 and 3000kVA	Standard	6	8,711		2,237	928	–	–	–	–	–	–	–	–	–
26	3.4	Between 150 and 3000kVA	Standard	185	129,615		–	–	51,680	18,838	43,126	15,971	–	–	–	–	–
27	3.5	Between 150 and 3000kVA	Standard	2	10,831		–	–	–	–	–	–	4,116	1,845	3,329	1,541	–
28	6.1	> 3000,	Non-standard	1	86,733		–	–	–	–	–	–	–	–	–	–	–
29	6.2	> 3000,	Non-standard	1	12,021		–	–	–	–	–	–	–	–	–	–	–
30	CB	Cobb River Hydro	Non-standard	1	86		–	–	–	–	–	–	–	–	–	–	–
31	Hydro	MAT, CB, EG etc	Non-standard	4	–		–	–	–	–	–	–	–	–	–	–	–
32	Connections	0	Standard	–	–		–	–	–	–	–	–	–	–	–	–	–
33	Solar Connections	0	Standard	–	–		–	–	–	–	–	–	–	–	–	–	–
35	*Add extra rows for additional consumer groups or price category codes as necessary*																
36			**Standard consumer totals**	42,809	551,047		2,237	928	51,680	18,838	43,126	15,971	4,116	1,845	3,329	1,541	–
37			**Non-standard consumer totals**	7	98,840		–	–	–	–	–	–	–	–	–	–	–
38			**Total for all consumers**	42,816	649,887		2,237	928	51,680	18,838	43,126	15,971	4,116	1,845	3,329	1,541	–

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2024**
Network / Sub-Network Name	

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

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	delivered to ICPs in disclosure year (MWh)	3.3GEN	3.4GEN	3.4GEN	6.1	6.2	NDL	NCA Admin G0	NCA Admin G1	NCA Admin G2	NCA Admin G3	CB
13					Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	kWh	kWh	kWh	Annual	Annual	kVA=km	New connection application	New connection application	New connection application	New connection application	Annual
15	0S	Unmetered Streetlamps	Standard	–	1,840	–	–	–	–	–	–	–	–	–	–	–
16	0UNM	Unmetered Supplies	Standard	69	13	–	–	–	–	–	–	–	–	–	–	–
17	1RL	15 kVA Capacity	Standard	19,133	107,337	–	–	–	–	–	–	–	–	–	–	–
18	1RS	15 kVA Capacity	Standard	16,792	149,097	–	–	–	–	–	–	–	–	–	–	–
19	1GL	15 kVA Capacity	Standard	3,666	23,084	–	–	–	–	–	–	–	–	–	–	–
20	2	20 - 150 kVA Capacity	Standard	2,886	104,870	–	–	–	–	–	–	–	–	–	–	–
21	2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	–	29	–	–	–	–	–	–	–	–	–	–	–
22	2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	62	473	–	–	–	–	–	–	–	–	–	–	–
23	HLF	High Load Factor, 15-150kVA Capacity	Standard	4	6,796	–	–	–	–	–	–	–	–	–	–	–
24	3.1	Between 150 and 3000kVA	Standard	4	8,351	–	–	–	–	–	–	–	–	–	–	–
25	3.3	Between 150 and 3000kVA	Standard	6	8,711	2,445	–	–	–	–	–	–	–	–	–	–
26	3.4	Between 150 and 3000kVA	Standard	185	129,615	–	164	–	–	–	–	–	–	–	–	–
27	3.5	Between 150 and 3000kVA	Standard	2	10,831	–	–	164	–	–	–	–	–	–	–	–
28	6.1	> 3000,	Non-standard	1	86,733	–	–	–	1	–	–	–	–	–	–	–
29	6.2	> 3000,	Non-standard	1	12,021	–	–	–	–	1	–	–	–	–	–	–
30	CB	Cobb River Hydro	Non-standard	1	86	–	–	–	–	–	–	–	–	–	–	–
31	Hydro	MAT, CB, EG etc	Non-standard	4	–	–	–	–	–	–	–	–	–	–	–	–
32	Connections	0	Standard	–	–	–	–	–	–	–	28,629	–	–	–	–	–
33	Solar Connections	0	Standard	–	–	–	–	–	–	–	–	–	491	55	13	–
34																
35	*Add extra rows for additional consumer groups or price category codes as necessary*															
36			**Standard consumer totals**	42,809	551,047	2,445	164	164	–	–	28,629	–	491	55	13	–
37			**Non-standard consumer totals**	7	98,840	–	–	–	1	1	–	–	–	–	–	–
38			**Total for all consumers**	42,816	649,887	2,445	164	164	1	1	28,629	–	491	55	13	–

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2024**
Network / Sub-Network Name	

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

					Price component	MAT	ONEKAK	WENLE	PUPU	Standard DG Part1A	Standard DG Part1	DG >10kw <100kW	DG >100kw <1000kW	DG >1MW
Consumer group name or price category code	**Standardised connection types**	**Standard or non-standard consumer group (specify)**	**Average no. of ICPs in disclosure year**	**delivered to ICPs in disclosure year (MWh)**	**Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)**	Annual	Annual	Annual	Annual	Per application	Per application	Per application	Per application	Per application
0S	Unmetered Streetlamps	Standard	–	1,840		–	–	–	–	–	–	–	–	–
0UNM	Unmetered Supplies	Standard	69	13		–	–	–	–	–	–	–	–	–
1RL	15 kVA Capacity	Standard	19,133	107,337		–	–	–	–	–	–	–	–	–
1RS	15 kVA Capacity	Standard	16,792	149,097		–	–	–	–	–	–	–	–	–
1GL	15 kVA Capacity	Standard	3,666	23,084		–	–	–	–	–	–	–	–	–
2	20 - 150 kVA Capacity	Standard	2,886	104,870		–	–	–	–	–	–	–	–	–
2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	–	29		–	–	–	–	–	–	–	–	–
2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	62	473		–	–	–	–	–	–	–	–	–
HLF	High Load Factor, 15-150kVA Capacity	Standard	4	6,796		–	–	–	–	–	–	–	–	–
3.1	Between 150 and 3000kVA	Standard	4	8,351		–	–	–	–	–	–	–	–	–
3.3	Between 150 and 3000kVA	Standard	6	8,711		–	–	–	–	–	–	–	–	–
3.4	Between 150 and 3000kVA	Standard	185	129,615		–	–	–	–	–	–	–	–	–
3.5	Between 150 and 3000kVA	Standard	2	10,831		–	–	–	–	–	–	–	–	–
6.1	> 3000,	Non-standard	1	86,733		–	–	–	–	–	–	–	–	–
6.2	> 3000,	Non-standard	1	12,021		–	–	–	–	–	–	–	–	–
CB	Cobb River Hydro	Non-standard	1	86		–	–	–	–	–	–	–	–	–
Hydro	MAT, CB, EG etc	Non-standard	4	–		1	1	1	1	–	–	–	–	–
Connections	0	Standard	–	–		–	–	–	–	–	–	–	–	–
Solar Connections	0	Standard	–	–		–	–	–	–	521	2	36	4	4
Add extra rows for additional consumer groups or price category codes as necessary														
		Standard consumer totals	42,809	551,047		–	–	–	–	521	2	36	4	4
		Non-standard consumer totals	7	98,840		1	1	1	1	–	–	–	–	–
		Total for all consumers	42,816	649,887		1	1	1	1	521	2	36	4	4

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2024**
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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.

41 **8(ii): Line Charge Revenues ($000) by Price Component**

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

Row	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	Price component / Rate (eg, $ per day, $ per kWh, etc.)	0STL	0UNM	1RLANY	1RLDAY	1RLDEF	1RLNIT	1RLOFP	1RLPEK	1RLWSR	1RLGEN	1RSANY
46								0.00115	0.6	0.0451	0.049	0.0451	0.0311	0.0417	0.0479	0.0322	0	0.0172
47					*Not Required after DY2024*													
48	0S	Unmetered Streetlamps	Standard	$177	151	26		$177	–	–	–	–	–	–	–	–	–	–
49	0UNM	Unmetered Supplies	Standard	$16	13	2		–	$16	–	–	–	–	–	–	–	–	–
50	1RL	15 kVA Capacity	Standard	$7,660	5,622	2,038		–	–	$1,114	$28	$184	$31	$1,015	$1,267	$853	–	–
51	1RS	15 kVA Capacity	Standard	$8,597	6,198	2,399		$1	–	–	–	–	–	–	–	–	–	$608
52	1GL	15 kVA Capacity	Standard	$1,820	1,337	483		$2	–	–	–	–	–	–	–	–	–	–
53	2	20 - 150 kVA Capacity	Standard	$8,105	6,082	2,024		$3	–	–	–	–	–	–	–	–	–	–
54	2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	$7	5	2		–	–	–	–	–	–	–	–	–	–	–
55	2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	$52	37	15		–	–	–	–	–	–	–	–	–	–	–
56	HLF	High Load Factor, 15-150kVA Capacity	Standard	$477	390	87		–	–	–	–	–	–	–	–	–	–	–
57	3.1	Between 150 and 3000kVA	Standard	$208	119	89		–	–	–	–	–	–	–	–	–	–	–
58	3.3	Between 150 and 3000kVA	Standard	$356	258	98		–	–	–	–	–	–	–	–	–	–	–
59	3.4	Between 150 and 3000kVA	Standard	$6,973	4,938	2,035		–	–	–	–	–	–	–	–	–	–	–
60	3.5	Between 150 and 3000kVA	Standard	$421	290	131		–	–	–	–	–	–	–	–	–	–	–
61	6.1	> 3000,	Non-standard	$1,347	219	1,128		–	–	–	–	–	–	–	–	–	–	–
62	6.2	> 3000,	Non-standard	$413	223	190		–	–	–	–	–	–	–	–	–	–	–
63	CB	-	Non-standard	$1,837	1,609	227		–	–	–	–	–	–	–	–	–	–	–
64	MAT	MAT, CB, EG etc	Non-standard	$20	18	3		–	–	–	–	–	–	–	–	–	–	–
65	Connections	-	Standard	$338	338	–		–	–	–	–	–	–	–	–	–	–	–
66	Solar Connections	-	Standard	$95	95	–		–	–	–	–	–	–	–	–	–	–	–
67	-	-	-	–	–	–		–	–	–	–	–	–	–	–	–	–	–
68	*Add extra rows for additional consumer groups or price category codes as necessary*																	
69			**Standard consumer totals**	$35,303	$25,874	$9,429		$183	$16	$1,114	$28	$184	$31	$1,015	$1,267	$853	–	$608
70			**Non-standard consumer totals**	$3,617	$2,069	$1,548		–	–	–	–	–	–	–	–	–	–	–
71			**Total for all consumers**	$38,920	$27,943	$10,977		$183	$16	$1,114	$28	$184	$31	$1,015	$1,267	$853	–	$608

73 **8(iii): Number of ICPs directly billed** **Check** OK

74 **Number of directly billed ICPs at year end** 4

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2024**
Network / Sub-Network Name	

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.

41 **8(ii): Line Charge Revenues ($000) by Price Component**

Row	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	Price component	1RSDAY	1RSDEF	1RSNIT	1RSOFP	1RSPEK	1RSWSR	1RSGEN	1GLANY	1GLDAY	1GLDEF	1GLNIT
46							Rate (eg, $ per day, $ per kWh, etc.)	0.0211	0.0172	0.0032	0.0138	0.02	0.0043	0	0.0172	0.0211	0.0172	0.0032
47					*Not Required after DY2024*													
48	0S	Unmetered Streetlamps	Standard	$177	151	26		–	–	–	–	–	–	–	–	–	–	–
49	0UNM	Unmetered Supplies	Standard	$16	13	2		–	–	–	–	–	–	–	–	–	–	–
50	1RL	15 kVA Capacity	Standard	$7,660	5,622	2,038		–	–	–	–	–	–	–	–	–	–	–
51	1RS	15 kVA Capacity	Standard	$8,597	6,198	2,399		$24	$104	$5	$483	$752	$145	–	–	–	–	–
52	1GL	15 kVA Capacity	Standard	$1,820	1,337	483		–	–	–	–	–	–	–	$86	$8	$47	$1
53	2	20 - 150 kVA Capacity	Standard	$8,105	6,082	2,024		–	–	–	–	–	–	–	–	–	–	–
54	2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	$7	5	2		–	–	–	–	–	–	–	–	–	–	–
55	2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	$52	37	15		–	–	–	–	–	–	–	–	–	–	–
56	HLF	High Load Factor, 15-150kVA Capacity	Standard	$477	390	87		–	–	–	–	–	–	–	–	–	–	–
57	3.1	Between 150 and 3000kVA	Standard	$208	119	89		–	–	–	–	–	–	–	–	–	–	–
58	3.3	Between 150 and 3000kVA	Standard	$356	258	98		–	–	–	–	–	–	–	–	–	–	–
59	3.4	Between 150 and 3000kVA	Standard	$6,973	4,938	2,035		–	–	–	–	–	–	–	–	–	–	–
60	3.5	Between 150 and 3000kVA	Standard	$421	290	131		–	–	–	–	–	–	–	–	–	–	–
61	6.1	> 3000,	Non-standard	$1,347	219	1,128		–	–	–	–	–	–	–	–	–	–	–
62	6.2	> 3000,	Non-standard	$413	223	190		–	–	–	–	–	–	–	–	–	–	–
63	CB	-	Non-standard	$1,837	1,609	227		–	–	–	–	–	–	–	–	–	–	–
64	MAT	MAT, CB, EG etc	Non-standard	$20	18	3		–	–	–	–	–	–	–	–	–	–	–
65	Connections	-	Standard	$338	338	–		–	–	–	–	–	–	–	–	–	–	–
66	Solar Connections	-	Standard	$95	95	–		–	–	–	–	–	–	–	–	–	–	–
67	-	-	-	–	–	–		–	–	–	–	–	–	–	–	–	–	–
68	*Add extra rows for additional consumer groups or price category codes as necessary*																	
69			**Standard consumer totals**	$35,303	$25,874	$9,429		$24	$104	$5	$483	$752	$145	–	$86	$8	$47	$1
70			**Non-standard consumer totals**	$3,617	$2,069	$1,548		–	–	–	–	–	–	–	–	–	–	–
71			**Total for all consumers**	$38,920	$27,943	$10,977		$24	$104	$5	$483	$752	$145	–	$86	$8	$47	$1

73 **8(iii): Number of ICPs directly billed**

Check OK

74 **Number of directly billed ICPs at year end** 4

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2024**
Network / Sub-Network Name	

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.

41 **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	Total transmission line charge revenue	Price component	1GLOFP	1GLPEK	1GLWSR	1GLGEN	2ANY	2DAY	2DEF	2NIT	2OFP	2PEK	2WSR
46							Rate (eg, $ per day, $ per kWh, etc.)	0.0138	0.02	0.0043	0	0.0295	0.034	0.0295	0.012	0.0236	0.0335	0.0162
47					*Not Required after DY2024*													
48	0S	Unmetered Streetlamps	Standard	$177	151	26		–	–	–	–	–	–	–	–	–	–	–
49	0UNM	Unmetered Supplies	Standard	$16	13	2		–	–	–	–	–	–	–	–	–	–	–
50	1RL	15 kVA Capacity	Standard	$7,660	5,622	2,038		–	–	–	–	–	–	–	–	–	–	–
51	1RS	15 kVA Capacity	Standard	$8,597	6,198	2,399		–	–	–	–	–	–	–	–	–	–	–
52	1GL	15 kVA Capacity	Standard	$1,820	1,337	483		$82	$148	$7	–	–	–	–	–	–	–	–
53	2	20 - 150 kVA Capacity	Standard	$8,105	6,082	2,024		–	–	–	–	$644	$378	$445	$57	$494	$960	$47
54	2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	$7	5	2		–	–	–	–	–	–	–	–	–	–	–
55	2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	$52	37	15		–	–	–	–	–	–	–	–	–	–	–
56	HLF	High Load Factor, 15-150kVA Capacity	Standard	$477	390	87		–	–	–	–	–	–	–	–	–	–	–
57	3.1	Between 150 and 3000kVA	Standard	$208	119	89		–	–	–	–	–	–	–	–	–	–	–
58	3.3	Between 150 and 3000kVA	Standard	$356	258	98		–	–	–	–	–	–	–	–	–	–	–
59	3.4	Between 150 and 3000kVA	Standard	$6,973	4,938	2,035		–	–	–	–	–	–	–	–	–	–	–
60	3.5	Between 150 and 3000kVA	Standard	$421	290	131		–	–	–	–	–	–	–	–	–	–	–
61	6.1	> 3000,	Non-standard	$1,347	219	1,128		–	–	–	–	–	–	–	–	–	–	–
62	6.2	> 3000,	Non-standard	$413	223	190		–	–	–	–	–	–	–	–	–	–	–
63	CB	-	Non-standard	$1,837	1,609	227		–	–	–	–	–	–	–	–	–	–	–
64	MAT	MAT, CB, EG etc	Non-standard	$20	18	3		–	–	–	–	–	–	–	–	–	–	–
65	Connections	-	Standard	$338	338	–		–	–	–	–	–	–	–	–	–	–	–
66	Solar Connections	-	Standard	$95	95	–		–	–	–	–	–	–	–	–	–	–	–
67	-	-	-	–	–	–		–	–	–	–	–	–	–	–	–	–	–
68	*Add extra rows for additional consumer groups or price category codes as necessary*																	
69			**Standard consumer totals**	$35,303	$25,874	$9,429		$82	$148	$7	–	$644	$378	$445	$57	$494	$960	$47
70			**Non-standard consumer totals**	$3,617	$2,069	$1,548		–	–	–	–	–	–	–	–	–	–	–
71			**Total for all consumers**	$38,920	$27,943	$10,977		$82	$148	$7	–	$644	$378	$445	$57	$494	$960	$47

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73 **8(iii): Number of ICPs directly billed**

74 **Number of directly billed ICPs at year end** 4

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2024**
Network / Sub-Network Name	

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.

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

						Price component	2GEN	2LANY	2LDAY	2LDEF	2LNIT	2LOFP	2LPEK	2LWSR	2LGEN	2HANY	2HDAY
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**	**Rate (eg, $ per day, $ per kWh, etc.)**	0	0.1045	0.109	0.1045	0.087	0.0986	0.1085	0.0912	0	0.2	0.2045
				Not Required after DY2024													
0S	Unmetered Streetlamps	Standard	$177	151	26		–	–	–	–	–	–	–	–	–	–	–
0UNM	Unmetered Supplies	Standard	$16	13	2		–	–	–	–	–	–	–	–	–	–	–
1RL	15 kVA Capacity	Standard	$7,660	5,622	2,038		–	–	–	–	–	–	–	–	–	–	–
1RS	15 kVA Capacity	Standard	$8,597	6,198	2,399		–	–	–	–	–	–	–	–	–	–	–
1GL	15 kVA Capacity	Standard	$1,820	1,337	483		–	–	–	–	–	–	–	–	–	–	–
2	20 - 150 kVA Capacity	Standard	$8,105	6,082	2,024		–	–	–	–	–	–	–	–	–	–	–
2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	$7	5	2		–	–	–	–	–	–	–	–	–	$1	–
2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	$52	37	15		–	$23	$2	$3	$1	$6	–	$5	–	–	–
HLF	High Load Factor, 15-150kVA Capacity	Standard	$477	390	87		–	–	–	–	–	–	–	–	–	–	–
3.1	Between 150 and 3000kVA	Standard	$208	119	89		–	–	–	–	–	–	–	–	–	–	–
3.3	Between 150 and 3000kVA	Standard	$356	258	98		–	–	–	–	–	–	–	–	–	–	–
3.4	Between 150 and 3000kVA	Standard	$6,973	4,938	2,035		–	–	–	–	–	–	–	–	–	–	–
3.5	Between 150 and 3000kVA	Standard	$421	290	131		–	–	–	–	–	–	–	–	–	–	–
6.1	> 3000,	Non-standard	$1,347	219	1,128		–	–	–	–	–	–	–	–	–	–	–
6.2	> 3000,	Non-standard	$413	223	190		–	–	–	–	–	–	–	–	–	–	–
CB	-	Non-standard	$1,837	1,609	227		–	–	–	–	–	–	–	–	–	–	–
MAT	MAT, CB, EG etc	Non-standard	$20	18	3		–	–	–	–	–	–	–	–	–	–	–
Connections	-	Standard	$338	338	–		–	–	–	–	–	–	–	–	–	–	–
Solar Connections	-	Standard	$95	95	–		–	–	–	–	–	–	–	–	–	–	–
-	-	-	–	–	–		–	–	–	–	–	–	–	–	–	–	–
Add extra rows for additional consumer groups or price category codes as necessary																	
		Standard consumer totals	$35,303	$25,874	$9,429		–	$23	$2	$3	$1	$6	–	$5	–	$1	–
		Non-standard consumer totals	$3,617	$2,069	$1,548		–	–	–	–	–	–	–	–	–	–	–
		Total for all consumers	$38,920	$27,943	$10,977		–	$23	$2	$3	$1	$6	–	$5	–	$1	–

8(iii): Number of ICPs directly billed

Check OK

Number of directly billed ICPs at year end 4

Company Name	**Network Tasman Limited**	
For Year Ended	**31 March 2024**	
Network / Sub-Network Name		

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.

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	Total transmission line charge revenue	Price component	2HDEF	2HNIT	2HOFP	2HPEK	2HWSR	2HGEN	HLFANY	HLFDAY	HLFDEF	HLFNIT	HLFOFP
						Rate (eg, $ per day, $ per kWh, etc.)	0.2	0.1825	0.1941	0.204	0.1867	0	0.0072	0.0083	0.0072	0.0016	0.0057
				Not Required after DY2024													
0S	Unmetered Streetlamps	Standard	$177	151	26		–	–	–	–	–	–	–	–	–	–	–
0UNM	Unmetered Supplies	Standard	$16	13	2		–	–	–	–	–	–	–	–	–	–	–
1RL	15 kVA Capacity	Standard	$7,660	5,622	2,038		–	–	–	–	–	–	–	–	–	–	–
1RS	15 kVA Capacity	Standard	$8,597	6,198	2,399		–	–	–	–	–	–	–	–	–	–	–
1GL	15 kVA Capacity	Standard	$1,820	1,337	483		–	–	–	–	–	–	–	–	–	–	–
2	20 - 150 kVA Capacity	Standard	$8,105	6,082	2,024		–	–	–	–	–	–	–	–	–	–	–
2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	$7	5	2		$0	–	$2	$2	$1	–	–	–	–	–	–
2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	$52	37	15		–	–	–	–	–	–	–	–	–	–	–
HLF	High Load Factor, 15-150kVA Capacity	Standard	$477	390	87		–	–	–	–	–	–	$3	$2	$6	$0	$14
3.1	Between 150 and 3000kVA	Standard	$208	119	89		–	–	–	–	–	–	–	–	–	–	–
3.3	Between 150 and 3000kVA	Standard	$356	258	98		–	–	–	–	–	–	–	–	–	–	–
3.4	Between 150 and 3000kVA	Standard	$6,973	4,938	2,035		–	–	–	–	–	–	–	–	–	–	–
3.5	Between 150 and 3000kVA	Standard	$421	290	131		–	–	–	–	–	–	–	–	–	–	–
6.1	> 3000,	Non-standard	$1,347	219	1,128		–	–	–	–	–	–	–	–	–	–	–
6.2	> 3000,	Non-standard	$413	223	190		–	–	–	–	–	–	–	–	–	–	–
CB	-	Non-standard	$1,837	1,609	227		–	–	–	–	–	–	–	–	–	–	–
MAT	MAT, CB, EG etc	Non-standard	$20	18	3		–	–	–	–	–	–	–	–	–	–	–
Connections	-	Standard	$338	338	–		–	–	–	–	–	–	–	–	–	–	–
Solar Connections	-	Standard	$95	95	–		–	–	–	–	–	–	–	–	–	–	–
-	-	-	–	–	–		–	–	–	–	–	–	–	–	–	–	–
Add extra rows for additional consumer groups or price category codes as necessary																	
		Standard consumer totals	$35,303	$25,874	$9,429		$0	–	$2	$2	$1	–	$3	$2	$6	$0	$14
		Non-standard consumer totals	$3,617	$2,069	$1,548		–	–	–	–	–	–	–	–	–	–	–
		Total for all consumers	$38,920	$27,943	$10,977		$0	–	$2	$2	$1	–	$3	$2	$6	$0	$14

8(iii): Number of ICPs directly billed

Check OK

Number of directly billed ICPs at year end 4

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2024**
Network / Sub-Network Name	

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.

41 ## 8(ii): Line Charge Revenues ($000) by Price Component

Row	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
47					*Not Required after DY2024*	
48	0S	Unmetered Streetlamps	Standard	$177	151	26
49	0UNM	Unmetered Supplies	Standard	$16	13	2
50	1RL	15 kVA Capacity	Standard	$7,660	5,622	2,038
51	1RS	15 kVA Capacity	Standard	$8,597	6,198	2,399
52	1GL	15 kVA Capacity	Standard	$1,820	1,337	483
53	2	20 - 150 kVA Capacity	Standard	$8,105	6,082	2,024
54	2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	$7	5	2
55	2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	$52	37	15
56	HLF	High Load Factor, 15-150kVA Capacity	Standard	$477	390	87
57	3.1	Between 150 and 3000kVA	Standard	$208	119	89
58	3.3	Between 150 and 3000kVA	Standard	$356	258	98
59	3.4	Between 150 and 3000kVA	Standard	$6,973	4,938	2,035
60	3.5	Between 150 and 3000kVA	Standard	$421	290	131
61	6.1	> 3000,	Non-standard	$1,347	219	1,128
62	6.2	> 3000,	Non-standard	$413	223	190
63	CB	-	Non-standard	$1,837	1,609	227
64	MAT	MAT, CB, EG etc	Non-standard	$20	18	3
65	Connections	-	Standard	$338	338	–
66	Solar Connections	-	Standard	$95	95	–
67	-	-	-	–	–	–
68	*Add extra rows for additional consumer groups or price category codes as necessary*					
69			**Standard consumer totals**	$35,303	$25,874	$9,429
70			**Non-standard consumer totals**	$3,617	$2,069	$1,548
71			**Total for all consumers**	$38,920	$27,943	$10,977

Row	Price component	HLFPEK	HLFWSR	HLFGEN	1RL	1RS	1GL	2	2HLFC	2LLFC	HLF	AnyDem31
46	Rate (eg, $ per day, $ per kWh, etc.)	0.0085	0.0015	0	0.45	1.06	1.06	0.1045	0.45	0.45	0.4322	0.113
48	0S	–	–	–	–	–	–	–	–	–	–	–
49	0UNM	–	–	–	–	–	–	–	–	–	–	–
50	1RL	–	–	–	$3,168	–	–	–	–	–	–	–
51	1RS	–	–	–	–	$6,475	–	–	–	–	–	–
52	1GL	–	–	–	–	–	$1,440	–	–	–	–	–
53	2	–	–	–	–	–	–	$5,077	–	–	–	–
54	2HLFC	–	–	–	–	–	–	–	$1	–	–	–
55	2LLFC	–	–	–	–	–	–	–	–	$12	–	–
56	HLF	$25	$0	–	–	–	–	–	–	–	$428	–
57	3.1	–	–	–	–	–	–	–	–	–	–	$85
58	3.3	–	–	–	–	–	–	–	–	–	–	–
59	3.4	–	–	–	–	–	–	–	–	–	–	–
60	3.5	–	–	–	–	–	–	–	–	–	–	–
61	6.1	–	–	–	–	–	–	–	–	–	–	–
62	6.2	–	–	–	–	–	–	–	–	–	–	–
63	CB	–	–	–	–	–	–	–	–	–	–	–
64	MAT	–	–	–	–	–	–	–	–	–	–	–
65	Connections	–	–	–	–	–	–	–	–	–	–	–
66	Solar Connections	–	–	–	–	–	–	–	–	–	–	–
67	-	–	–	–	–	–	–	–	–	–	–	–
69	Standard consumer totals	$25	$0	–	$3,168	$6,475	$1,440	$5,077	$1	$12	$428	$85
70	Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–	–
71	Total for all consumers	$25	$0	–	$3,168	$6,475	$1,440	$5,077	$1	$12	$428	$85

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73 ## 8(iii): Number of ICPs directly billed

74 **Number of directly billed ICPs at year end** 4

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2024**
Network / Sub-Network Name	

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.

41 ## 8(ii): Line Charge Revenues ($000) by Price Component

Row	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	Rate (eg, $ per day, $ per kWh, etc.)	AnyDem33	AnyDem34	AnyDem35	Any_T	kVAr	SD31	SN31	WD31	WN31	SD33	SN33
45							**Price component**	AnyDem33	AnyDem34	AnyDem35	Any_T	kVAr	SD31	SN31	WD31	WN31	SD33	SN33
46								0.1333	0.1419	0.1333	0.1116	0.3111	0.0043	0.002	0.0076	0.002	0.0128	0.007
47					*Not Required after DY2024*													
48	0S	Unmetered Streetlamps	Standard	$177	151	26		–	–	–	–	–	–	–	–	–	–	–
49	0UNM	Unmetered Supplies	Standard	$16	13	2		–	–	–	–	–	–	–	–	–	–	–
50	1RL	15 kVA Capacity	Standard	$7,660	5,622	2,038		–	–	–	–	–	–	–	–	–	–	–
51	1RS	15 kVA Capacity	Standard	$8,597	6,198	2,399		–	–	–	–	–	–	–	–	–	–	–
52	1GL	15 kVA Capacity	Standard	$1,820	1,337	483		–	–	–	–	–	–	–	–	–	–	–
53	2	20 - 150 kVA Capacity	Standard	$8,105	6,082	2,024		–	–	–	–	–	–	–	–	–	–	–
54	2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	$7	5	2		–	–	–	–	–	–	–	–	–	–	–
55	2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	$52	37	15		–	–	–	–	–	–	–	–	–	–	–
56	HLF	High Load Factor, 15-150kVA Capacity	Standard	$477	390	87		–	–	–	–	–	–	–	–	–	–	–
57	3.1	Between 150 and 3000kVA	Standard	$208	119	89		–	–	–	$84	–	$15	$3	$19	$2	–	–
58	3.3	Between 150 and 3000kVA	Standard	$356	258	98		$122	–	–	$93	–	–	–	–	–	$49	$12
59	3.4	Between 150 and 3000kVA	Standard	$6,973	4,938	2,035		–	$2,711	–	$1,920	$11	–	–	–	–	–	–
60	3.5	Between 150 and 3000kVA	Standard	$421	290	131		–	–	$148	$124	–	–	–	–	–	–	–
61	6.1	> 3000,	Non-standard	$1,347	219	1,128		–	–	–	–	–	–	–	–	–	–	–
62	6.2	> 3000,	Non-standard	$413	223	190		–	–	–	–	–	–	–	–	–	–	–
63	CB	-	Non-standard	$1,837	1,609	227		–	–	–	–	–	–	–	–	–	–	–
64	MAT	MAT, CB, EG etc	Non-standard	$20	18	3		–	–	–	–	–	–	–	–	–	–	–
65	Connections	-	Standard	$338	338	–		–	–	–	–	–	–	–	–	–	–	–
66	Solar Connections	-	Standard	$95	95	–		–	–	–	–	–	–	–	–	–	–	–
67	-	-	-	–	–	–		–	–	–	–	–	–	–	–	–	–	–
68	*Add extra rows for additional consumer groups or price category codes as necessary*																	
69			**Standard consumer totals**	$35,303	$25,874	$9,429		$122	$2,711	$148	$2,221	$11	$15	$3	$19	$2	$49	$12
70			**Non-standard consumer totals**	$3,617	$2,069	$1,548		–	–	–	–	–	–	–	–	–	–	–
71			**Total for all consumers**	$38,920	$27,943	$10,977		$122	$2,711	$148	$2,221	$11	$15	$3	$19	$2	$49	$12

73 ## 8(iii): Number of ICPs directly billed

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Row		
74	**Number of directly billed ICPs at year end**	4

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2024**
Network / Sub-Network Name	

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.

41 **8(ii): Line Charge Revenues ($000) by Price Component**

							Price component	WD33	WN33	SD34	SN34	WD34	WN34	SD35	SN35	WD35	WN35	3.1GEN
46	**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**	**Rate (eg, $ per day, $ per kWh, etc.)**	0.033	0.007	0.0128	0.007	0.033	0.007	0.0088	0.0054	0.0281	0.0054	0
47					*Not Required after DY2024*													
48	0S	Unmetered Streetlamps	Standard	$177	151	26		–	–	–	–	–	–	–	–	–	–	–
49	0UNM	Unmetered Supplies	Standard	$16	13	2		–	–	–	–	–	–	–	–	–	–	–
50	1RL	15 kVA Capacity	Standard	$7,660	5,622	2,038		–	–	–	–	–	–	–	–	–	–	–
51	1RS	15 kVA Capacity	Standard	$8,597	6,198	2,399		–	–	–	–	–	–	–	–	–	–	–
52	1GL	15 kVA Capacity	Standard	$1,820	1,337	483		–	–	–	–	–	–	–	–	–	–	–
53	2	20 - 150 kVA Capacity	Standard	$8,105	6,082	2,024		–	–	–	–	–	–	–	–	–	–	–
54	2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	$7	5	2		–	–	–	–	–	–	–	–	–	–	–
55	2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	$52	37	15		–	–	–	–	–	–	–	–	–	–	–
56	HLF	High Load Factor, 15-150kVA Capacity	Standard	$477	390	87		–	–	–	–	–	–	–	–	–	–	–
57	3.1	Between 150 and 3000kVA	Standard	$208	119	89		–	–	–	–	–	–	–	–	–	–	–
58	3.3	Between 150 and 3000kVA	Standard	$356	258	98		$74	$7	–	–	–	–	–	–	–	–	–
59	3.4	Between 150 and 3000kVA	Standard	$6,973	4,938	2,035		–	–	$663	$132	$1,425	$112	–	–	–	–	–
60	3.5	Between 150 and 3000kVA	Standard	$421	290	131		–	–	–	–	–	–	$36	$10	$94	$8	–
61	6.1	> 3000,	Non-standard	$1,347	219	1,128		–	–	–	–	–	–	–	–	–	–	–
62	6.2	> 3000,	Non-standard	$413	223	190		–	–	–	–	–	–	–	–	–	–	–
63	CB	-	Non-standard	$1,837	1,609	227		–	–	–	–	–	–	–	–	–	–	–
64	MAT	MAT, CB, EG etc	Non-standard	$20	18	3		–	–	–	–	–	–	–	–	–	–	–
65	Connections	-	Standard	$338	338	–		–	–	–	–	–	–	–	–	–	–	–
66	Solar Connections	-	Standard	$95	95	–		–	–	–	–	–	–	–	–	–	–	–
67	-	-	-	–	–	–		–	–	–	–	–	–	–	–	–	–	–
68	*Add extra rows for additional consumer groups or price category codes as necessary*																	
69			**Standard consumer totals**	$35,303	$25,874	$9,429		$74	$7	$663	$132	$1,425	$112	$36	$10	$94	$8	–
70			**Non-standard consumer totals**	$3,617	$2,069	$1,548		–	–	–	–	–	–	–	–	–	–	–
71			**Total for all consumers**	$38,920	$27,943	$10,977		$74	$7	$663	$132	$1,425	$112	$36	$10	$94	$8	–

73 **8(iii): Number of ICPs directly billed** — **Check** OK

74 **Number of directly billed ICPs at year end** 4

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2024**
Network / Sub-Network Name	

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.

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	Total transmission line charge revenue	Price component / Rate (eg, $ per day, $ per kWh, etc.)	3.3GEN	3.4GEN	3.4GEN	6.1	6.2	NDL	NCA Admin G0	NCA Admin G1	NCA Admin G2	NCA Admin G3	CB
						Rate	0	0	0	Annual	Annual	7.714143	125	250	325	400	Annual
				Not Required after DY2024													
0S	Unmetered Streetlamps	Standard	$177	151	26		–	–	–	–	–	–	–	–	–	–	–
0UNM	Unmetered Supplies	Standard	$16	13	2		–	–	–	–	–	–	–	–	–	–	–
1RL	15 kVA Capacity	Standard	$7,660	5,622	2,038		–	–	–	–	–	–	–	–	–	–	–
1RS	15 kVA Capacity	Standard	$8,597	6,198	2,399		–	–	–	–	–	–	–	–	–	–	–
1GL	15 kVA Capacity	Standard	$1,820	1,337	483		–	–	–	–	–	–	–	–	–	–	–
2	20 - 150 kVA Capacity	Standard	$8,105	6,082	2,024		–	–	–	–	–	–	–	–	–	–	–
2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	$7	5	2		–	–	–	–	–	–	–	–	–	–	–
2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	$52	37	15		–	–	–	–	–	–	–	–	–	–	–
HLF	High Load Factor, 15-150kVA Capacity	Standard	$477	390	87		–	–	–	–	–	–	–	–	–	–	–
3.1	Between 150 and 3000kVA	Standard	$208	119	89		–	–	–	–	–	–	–	–	–	–	–
3.3	Between 150 and 3000kVA	Standard	$356	258	98		–	–	–	–	–	–	–	–	–	–	–
3.4	Between 150 and 3000kVA	Standard	$6,973	4,938	2,035		–	–	–	–	–	–	–	–	–	–	–
3.5	Between 150 and 3000kVA	Standard	$421	290	131		–	–	–	–	–	–	–	–	–	–	–
6.1	> 3000,	Non-standard	$1,347	219	1,128		–	–	–	$1,347	–	–	–	–	–	–	–
6.2	> 3000,	Non-standard	$413	223	190		–	–	–	–	$413	–	–	–	–	–	–
CB	-	Non-standard	$1,837	1,609	227		–	–	–	–	–	–	–	–	–	–	$1,837
MAT	MAT, CB, EG etc	Non-standard	$20	18	3		–	–	–	–	–	–	–	–	–	–	–
Connections	-	Standard	$338	338	–		–	–	–	–	–	$192	–	$123	$18	$5	–
Solar Connections	-	Standard	$95	95	–		–	–	–	–	–	–	–	–	–	–	–
-	-	-	–	–	–		–	–	–	–	–	–	–	–	–	–	–
Add extra rows for additional consumer groups or price category codes as necessary																	
		Standard consumer totals	$35,303	$25,874	$9,429		–	–	–	–	–	$192	–	$123	$18	$5	–
		Non-standard consumer totals	$3,617	$2,069	$1,548		–	–	–	$1,347	$413	–	–	–	–	–	$1,837
		Total for all consumers	$38,920	$27,943	$10,977		–	–	–	$1,347	$413	$192	–	$123	$18	$5	$1,837

Check OK

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end 4

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2024**
Network / Sub-Network Name	

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.

41 **8(ii): Line Charge Revenues ($000) by Price Component**

Row	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	Rate (eg, $ per day, $ per kWh, etc.)	MAT	ONEKAK	WENLE	PUPU	Standard DG Part1A	Standard DG Part1	DG >10kw <100kW	DG >100kw <1000kW	DG >100kw <1000kW
45							Price component	MAT	ONEKAK	WENLE	PUPU	Standard DG Part1A	Standard DG Part1	DG >10kw <100kW	DG >100kw <1000kW	DG >100kw <1000kW
46								Annual	Annual	Annual	Annual	100	200	500	1000	5000
47					*Not Required after DY2024*											
48	0S	Unmetered Streetlamps	Standard	$177	151	26		–	–	–	–	–	–	–	–	–
49	0UNM	Unmetered Supplies	Standard	$16	13	2		–	–	–	–	–	–	–	–	–
50	1RL	15 kVA Capacity	Standard	$7,660	5,622	2,038		–	–	–	–	–	–	–	–	–
51	1RS	15 kVA Capacity	Standard	$8,597	6,198	2,399		–	–	–	–	–	–	–	–	–
52	1GL	15 kVA Capacity	Standard	$1,820	1,337	483		–	–	–	–	–	–	–	–	–
53	2	20 - 150 kVA Capacity	Standard	$8,105	6,082	2,024		–	–	–	–	–	–	–	–	–
54	2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	$7	5	2		–	–	–	–	–	–	–	–	–
55	2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	$52	37	15		–	–	–	–	–	–	–	–	–
56	HLF	High Load Factor, 15-150kVA Capacity	Standard	$477	390	87		–	–	–	–	–	–	–	–	–
57	3.1	Between 150 and 3000kVA	Standard	$208	119	89		–	–	–	–	–	–	–	–	–
58	3.3	Between 150 and 3000kVA	Standard	$356	258	98		–	–	–	–	–	–	–	–	–
59	3.4	Between 150 and 3000kVA	Standard	$6,973	4,938	2,035		–	–	–	–	–	–	–	–	–
60	3.5	Between 150 and 3000kVA	Standard	$421	290	131		–	–	–	–	–	–	–	–	–
61	6.1	> 3000,	Non-standard	$1,347	219	1,128		–	–	–	–	–	–	–	–	–
62	6.2	> 3000,	Non-standard	$413	223	190		–	–	–	–	–	–	–	–	–
63	CB	-	Non-standard	$1,837	1,609	227		–	–	–	–	–	–	–	–	–
64	MAT	MAT, CB, EG etc	Non-standard	$20	18	3		$13	$6	$0	$1	–	–	–	–	–
65	Connections	-	Standard	$338	338	–		–	–	–	–	–	–	–	–	–
66	Solar Connections	-	Standard	$95	95	–		–	–	–	–	$52	$0	$18	$4	$20
67	-	-	-	–	–	–		–	–	–	–	–	–	–	–	–
68	*Add extra rows for additional consumer groups or price category codes as necessary*															
69			**Standard consumer totals**	$35,303	$25,874	$9,429		–	–	–	–	$52	$0	$18	$4	$20
70			**Non-standard consumer totals**	$3,617	$2,069	$1,548		$13	$6	$0	$1	–	–	–	–	–
71			**Total for all consumers**	$38,920	$27,943	$10,977		$13	$6	$0	$1	$52	$0	$18	$4	$20

73 **8(iii): Number of ICPs directly billed** — **Check** OK

74 **Number of directly billed ICPs at year end** 4

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2024**
Network / Sub-network Name	

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

	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.	26,409	26,373	(36)	3
10	All	Overhead Line	Wood poles	No.	1,721	1,750	29	3
11	All	Overhead Line	Other pole types	No.	320	332	12	3
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	281	281	–	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	4
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	38	41	3	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	4
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	3	3	–	4
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	4
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	4
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	4
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	4
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	4
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	14	14	–	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	4
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	4
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	9	10	1	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	4
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	109	106	(3)	4
29	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	4
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	15	15	–	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	22	28	6	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	104	104	–	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	8	8	–	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	27	28	1	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1,887	1,876	(11)	3
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	3
37	HV	Distribution Line	SWER conductor	km	–	–	–	4
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	173	180	7	3
39	HV	Distribution Cable	Distribution UG PILC	km	135	133	(2)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	72	73	1	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1,387	1,420	33	3
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	158	159	1	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	152	159	7	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	3,831	3,823	(8)	3
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	853	873	20	3
48	HV	Distribution Transformer	Voltage regulators	No.	9	9	–	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	25	25	–	4
50	LV	LV Line	LV OH Conductor	km	486	483	(3)	3
51	LV	LV Cable	LV UG Cable	km	712	724	12	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	–	4
53	LV	Connections	OH/UG consumer service connections	No.	43,073	43,577	504	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	123	128	5	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	9	9	–	4
57	All	Load Control	Centralised plant	Lot	5	5	–	4
58	All	Load Control	Relays	No	–	–	–	4
59	All	Civils	Cable Tunnels	km	–	–	–	4

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2024**
Network / Sub-network Name	

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)** **31 March 2024**

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
9																								
10	All	Overhead Line	Concrete poles / steel structure	No	1,966	1,250	6,859	6,065	1,957	3,540	993	63	180	124	169	162	91	167	170	155	132	189	134	137
11	All	Overhead Line	Wood poles	No	–	65	203	186	140	179	178	17	21	9	8	21	3	7	12	11	8	56	13	15
12	All	Overhead Line	Other pole types	No	–	–	–	68	59	90	51	–	4	1	–	–	1	–	1	4	–	1	–	–
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	96	98	2	10	61	3	3	–	2	2	1	1	–	–	1	–	–	–	–
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	–	2	1	–	–	–	–	6	–	8	–	–	1	–	–	–
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	–	1	–	–	2	–	–	–	–	–	–	–	–	–	–	–	–
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	–	–	2	–	1	4	2	–	–	–	–	–	–	2	–	–	–	–	–	–
25	HV	Zone substation Buildings	Zone substations 110kV+	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No	–	–	–	–	–	–	6	–	–	–	–	–	–	–	1	–	–	–	–	1
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No	–	–	5	5	14	15	12	1	–	1	2	6	2	1	2	–	–	–	–	–
30	HV	Zone substation switchgear	33kV RMU	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No	–	–	–	–	–	–	–	–	–	–	–	–	–	4	5	–	–	–	–	–
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No	–	–	–	2	2	10	1	–	–	–	–	–	1	–	–	2	2	–	–	–
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No	–	–	–	–	–	10	18	–	13	–	12	–	9	14	–	–	–	–	–	–
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No	–	–	–	–	–	–	2	–	–	–	–	–	2	–	–	–	4	–	–	–
35	HV	Zone Substation Transformer	Zone Substation Transformers	No	–	–	2	2	5	5	1	–	–	–	2	–	2	–	2	–	1	–	–	–
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	39	83	461	503	154	274	103	7	7	7	12	12	6	10	3	8	13	34	16	12
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
38	HV	Distribution Line	SWER conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	–	–	–	–	13	8	1	2	2	12	6	6	12	10	8	7	4	3	3
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	3	21	40	23	2	2	2	12	6	2	4	3	3	2	1	1	1
41	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No	–	–	–	–	–	–	–	2	–	–	1	2	2	2	–	–	–	4	8	8
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No	–	–	–	–	6	12	11	8	15	16	25	39	43	17	40	33	25	11	19	19
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No	–	–	–	–	–	1	1	4	3	3	11	3	13	13	6	10	11	13	3	4
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No	–	–	–	–	1	–	–	1	1	1	4	1	4	1	1	1	2	2	3	–
47	HV	Distribution Transformer	Pole Mounted Transformer	No	24	61	181	487	453	851	585	36	75	81	64	68	43	37	22	42	42	43	31	44
48	HV	Distribution Transformer	Ground Mounted Transformer	No	–	–	4	9	77	116	75	14	16	31	28	28	27	39	24	28	24	19	16	5
49	HV	Distribution Transformer	Voltage regulators	No	–	–	–	–	–	–	2	–	–	–	–	–	2	–	–	–	–	1	–	–
50	HV	Distribution Substations	Ground Mounted Substation Housing	No	–	–	–	–	20	–	5	–	–	–	–	–	–	–	–	–	–	–	–	–
51	LV	LV Line	LV OH Conductor	km	–	14	143	118	41	58	12	76	1	1	1	2	2	3	1	1	2	1	1	1
52	LV	LV Cable	LV UG Cable	km	–	–	3	7	87	124	105	8	15	28	27	25	19	18	17	14	18	15	12	9
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
54	LV	Connections	OH/UG consumer service connections	No	–	–	–	–	–	–	–	–	626	640	829	877	702	597	622	661	595	459	537	464
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No	–	–	–	–	2	4	22	–	10	–	10	–	12	13	1	1	1	–	11	–
56	All	SCADA and communications	SCADA and communications equipment operating as a single systen	Lot	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	–	–	–	2	–	–	–	–	–	1	2	2	–	–
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	–	2	1	–	–	–	–	–	–	–	–	–	2	–	–
59	All	Load Control	Relays	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–

Company Name

For Year Ended

Network / Sub-network Name

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)** **31 March 2024**

sch ref	Voltage	Asset category	Asset class	Units	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	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	128	150	203	33	130	70	100	155	117	91	263	24	406	26,373	–	1
11	All	Overhead Line	Wood poles	No	14	29	–	–	8	42	84	93	4	6	34	29	255	1,750	–	1
12	All	Overhead Line	Other pole types	No	1	–	–	–	–	–	–	–	–	–	–	–	51	332	–	1
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	1	–	–	–	–	–	–	–	–	–	–	–	–	281	–	2
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	9	–	–	–	–	–	–	7	–	–	4	3	–	41	–	2
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	3	–	2
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2
24	HV	Zone substation Buildings	Zone substations up to 66kV	No	–	–	–	1	–	–	–	–	–	1	–	1	–	14	–	3
25	HV	Zone substation Buildings	Zone substations 110kV+	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No	–	–	–	1	–	–	–	–	–	–	–	1	–	10	–	4
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No	–	–	–	–	–	1	–	–	2	5	–	–	32	106	–	1
30	HV	Zone substation switchgear	33kV RMU	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No	–	–	–	–	–	–	–	–	–	6	–	–	–	15	–	4
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No	–	–	–	–	–	–	–	–	2	–	–	6	–	28	–	3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No	8	–	–	12	–	–	–	–	–	8	–	–	–	104	–	4
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No	–	–	–	–	–	–	–	–	–	–	–	–	–	8	–	3
35	HV	Zone Substation Transformer	Zone Substation Transformers	No	–	–	–	2	–	–	–	–	–	2	–	2	–	28	–	4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	16	6	2	–	6	8	21	21	20	10	–	2	–	1,876	–	2
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4
38	HV	Distribution Line	SWER conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	5	3	3	–	5	9	8	8	9	3	23	7	–	180	–	2
40	HV	Distribution Cable	Distribution UG PILC	km	2	1	2	–	–	–	–	–	–	–	–	–	–	133	–	2
41	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No	4	6	4	5	6	1	8	8	–	–	1	1	–	73	–	2
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	10	13	25	5	7	13	34	18	10	25	39	33	849	1,420	–	2
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No	4	8	9	–	5	2	5	5	–	8	4	1	9	159	–	2
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No	–	2	–	–	4	6	15	10	11	7	5	7	69	159	–	2
47	HV	Distribution Transformer	Pole Mounted Transformer	No	76	49	26	43	53	33	75	81	46	38	33	–	–	3,823	–	3
48	HV	Distribution Transformer	Ground Mounted Transformer	No	17	30	20	26	20	39	36	22	30	37	9	7	–	873	–	3
49	HV	Distribution Transformer	Voltage regulators	No	–	–	–	–	–	–	–	–	–	–	–	–	4	9	–	2
50	HV	Distribution Substations	Ground Mounted Substation Housing	No	–	–	–	–	–	–	–	–	–	–	–	–	–	25	–	2
51	LV	LV Line	LV OH Conductor	km	–	1	–	–	1	–	–	–	–	–	–	–	2	483	–	2
52	LV	LV Cable	LV UG Cable	km	9	11	12	3	14	13	17	16	19	13	18	12	13	724	–	2
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2
54	LV	Connections	OH/UG consumer service connections	No	460	557	442	447	538	562	529	622	723	643	695	504	29,246	43,577	–	2
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No	7	–	–	13	–	1	13	–	1	6	–	–	–	128	–	4
56	All	SCADA and communications	SCADA and communications equipment operating as a single systen	Lot	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	3
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	1	–	1	–	–	–	–	–	–	–	9	–	3
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	–	–	–	–	–	–	–	–	5	–	4
59	All	Load Control	Relays	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2024**
Network / Sub-network Name	

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	Circuit length by operating voltage (at year end)	Overhead (km)	Underground (km)	Total circuit length (km)
12	> 66kV	–	–	–
13	50kV & 66kV	158	–	158
14	33kV	123	41	164
15	SWER (all SWER voltages)	–	–	–
16	22kV (other than SWER)	19	13	31
17	6.6kV to 11kV (inclusive—other than SWER)	1,872	301	2,173
18	Low voltage (< 1kV)	483	724	1,207
19	**Total circuit length (for supply)**	2,655	1,079	3,733
21	Dedicated street lighting circuit length (km)	–	–	–
22	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			18

sch ref	Overhead circuit length by terrain (at year end)	Circuit length (km)	(% of total overhead length)
25	Urban	176	7%
26	Rural	2,283	86%
27	Remote only	70	3%
28	Rugged only	118	4%
29	Remote and rugged	8	0%
30	Unallocated overhead lines	–	–
31	**Total overhead length**	2,655	100%

sch ref		Circuit length (km)	(% of total circuit length)
34	Length of circuit within 10km of coastline or geothermal areas (where know	1,671	45%

sch ref		Circuit length (km)	(% of total overhead length)	
37	Overhead circuit requiring vegetation management	2,655	100%	*Not required after DY2025*

sch ref		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*

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	
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	**Network Tasman 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)
9	N/A		
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	**Network Tasman Limited**
For Year Ended	**31 March 2024**
Network / Sub-network Name	

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	Consumers 20kVA and less	525	
12	Consumers greater than 20kVA	42	
13	-	–	
14	-	–	
15	-	–	
16	** include additional rows if needed*		
17	**Connections total**	567	
18			
19	*Number of ICPs decommissioned during year by consumer type*		
20	*Consumer types defined by EDB**	**Number of decommissionings**	
21	Consumers 20kVA and less	63	
22	Consumers greater than 20kVA	18	
23	-	–	
24	-	–	
25	-	–	
26	** include additional rows if needed*		
27	**Decommissionings total**	81	
29	**Distributed generation**		
30	Number of connections made in year	479	**connections**
31	Capacity of distributed generation installed in year	3.41	**MVA**
33	**9e(ii): System Demand**		
36	**Maximum coincident system demand**	**Demand at time of maximum coincident demand (MW)**	
37	GXP demand	119	
38	*plus* Distributed generation output at HV and above	36	
39	**Maximum coincident system demand**	155	
40	*less* Net transfers to (from) other EDBs at HV and above	22	
41	**Demand on system for supply to consumers' connection points**	133	
42	**Electricity volumes carried**	**Energy (GWh)**	
43	Electricity supplied from GXPs	639	
44	*less* Electricity exports to GXPs	75	
45	*plus* Electricity supplied from distributed generation	210	
46	*less* Net electricity supplied to (from) other EDBs	90	
47	**Electricity entering system for supply to consumers' connection points**	684	
48	*less* Total energy delivered to ICPs	650	
49	**Electricity losses (loss ratio)**	34	5.0%
50			
51	**Load factor**	0.59	
52	**9e(iii): Transformer Capacity**		
53		**(MVA)**	
54	Distribution transformer capacity (EDB owned)	476	
55	Distribution transformer capacity (Non-EDB owned)	44	
56	**Total distribution transformer capacity**	520	
58		**(MVA)**	
59	Zone substation transformer capacity (EDB owned)	402	
60	Zone substation transformer capacity (Non-EDB owned)	–	
61	**Total zone substation transformer capacity**	402	

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2024**
Network / Sub-network Name	

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)	8
11	Class B (planned interruptions on the network)	199
12	Class C (unplanned interruptions on the network)	134
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 entit	–
17	Class H (planned interruptions caused by another disclosing entity)	–
18	Class I (interruptions caused by parties not included above)	–
19	**Total**	341
20		

sch ref		≤3Hrs	>3hrs
21	**Interruption restoration**		
22	Class C interruptions restored within	100	34
23			

sch ref		SAIFI	SAIDI
24	**SAIFI and SAIDI by class**		
25	Class A (planned interruptions by Transpower)	0.06	19.3
26	Class B (planned interruptions on the network)	0.31	104.7
27	Class C (unplanned interruptions on the network)	1.53	128.5
28	Class D (unplanned interruptions by Transpower)	–	–
29	Class E (unplanned interruptions of EDB owned generation)	–	–
30	Class F (unplanned interruptions of generation owned by others)	–	–
31	Class G (unplanned interruptions caused by another disclosing entit	–	–
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	–	–
34	**Total**	1.89	252.6
35			

sch ref		Normalised SAIFI	Normalised SAIDI	
36	**Normalised SAIFI and SAIDI**			
37	Classes B & C (interruptions on the network)	1.76	214.2	*Not required after DY2024*
38				

sch ref		SAIFI	SAIDI
39	**Transitional SAIFI and SAIDI (previous method)**		
40	Class B (planned interruptions on the network)	0.30	103.8
41	Class C (unplanned interruptions on the network)	1.24	133.1
42			

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.***

43

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2024**
Network / Sub-network Name	

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	0.27	8.3	
Vegetation	0.00	0.2	
Adverse weather	0.07	12.9	
Adverse environment	–	–	
Third party interference	0.13	14.8	
Wildlife	0.06	3.5	
Human error	–	–	
Defective equipment	0.81	75.1	
Cause unknown	0.18	13.7	*Not required after DY2024*
Other cause	–	–	*Not required before DY2025*
Unknown	–	–	*Not required before DY2025*

Breakdown of third party interference	SAIFI	SAIDI
Dig-in	–	–
Overhead contact	0.06	9.2
Vandalism	–	–
Vehicle damage	0.04	4.9
Other	0.03	0.6

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	0.8
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	0.26	89.3
Distribution cables (excluding LV)	0.03	11.6
Distribution other (excluding LV)	0.01	3.1

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.89	70.5
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	0.55	51.2
Distribution cables (excluding LV)	0.07	5.3
Distribution other (excluding LV)	0.02	1.5

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	5	281	1.78
Subtransmission cables	–	41	–
Subtransmission other	–		
Distribution lines (excluding LV)	99	1,891	5.24
Distribution cables (excluding LV)	11	314	3.51
Distribution other (excluding LV)	3		
Total	118		

Company Name	Network Tasman Limited
For Year Ended	31 March 2024

Schedule 14 Mandatory Explanatory Notes

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

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

2. This schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.1. Information provided in boxes 1 to 11 of this schedule is part of the audited disclosure information, and so is subject to the assurance requirements specified in section 2.8.

3. Schedule 15 (Voluntary Explanatory Notes to Schedules) provides for EDBs to give additional explanation of disclosed information should they elect to do so.

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

Network Tasman's use of posted discounts has traditionally resulted in a low return on investment, relative to the regulated WACC benchmarks. This is because posted discounts reduce Network Tasman's regulated prices/revenues and therefore return on investment.

Regulatory Profit (Schedule 3)

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

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

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

Box 2: Explanatory comment on regulatory profit

Other income includes Nelson Electricity Limited management fee $49,000 and sundry income of $31,000.

Nelson Electricity Limited sales and the related transmission costs have been excluded from the regulatory profit. These amounts net to zero.

Network Tasman derived an IRIS benefit of +$736,000 in 2023/24. This IRIS benefit was derived in accordance with clause 3.3.1 of the Electricity Distribution Services Input Methodologies Determination 2012.

There have been no changes in classification.

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 mergers and acquisitions.

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)

There have not been any changes in classification.

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

- Non-deductible expenses (non-deductible entertainment expenses)

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)
Loss on disposal of assets temporary difference $651,000 @28% = $182,300,

less movement in provisions temporary difference $46,000 @28% = $12,900.

Making temporary differences of $169,400.

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
Costs relating to unregulated businesses have been identified and excluded from the regulated business costs.

The allocation method is ABAA (Accounting-based allocation approach). This has resulted in a cost allocation of $1,211,000.

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
The allocation method is to ABAA (Accounting-based allocation approach). This has resulted in an asset allocation that increased the regulatory asset base by $264,000 in the current year.

There is no impact on the asset allocations from the asset reclassifications identified in box 4.

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

The materiality threshold of $300,000 has been used when identifying major network projects.

No items have been reclassified.

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, 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

Where a complete asset or a significant part of an asset is replaced or renewed then the expenditure is treated as capital. Where only some minor components are replaced or renewed then the expenditure is treated as operating expenditure.

Expenditure associated with portable generators has been reclassified from Service interruptions and emergencies to Routine and corrective maintenance and inspection.

There was no material atypical expenditure.

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

Capital Expenditure

- Customer connection expenditure is $185,000 over target due to transformers being required for new connections.

- Asset relocations are $497,000 under target. An allowance for undergrounding is budgeted for, but the actual undergrounding only occurs in conjunction with council work. There were no suitable council projects during the year.

- Asset replacement and renewal costs under target by $253,000. This is due to a combination of reasons.

  - SEL 551 Protection Relay Replacements, Refurbish Power Transformers and PILC HV Cable Replacements being delayed until the next year.

  - Zone Substation Upgrades and Pole Replacements being more expensive than expected.

  - Additional transformer replacement expenditure with a programme to proactively replace the oldest transformers.

- Reliability, safety and environment – quality of supply is over target by $838,000.

  - Increase due to the timing of a major project, Founders to Wakapuaka 33kV Cable. The contractor was able to progress the project at a faster rate than planned.

  - *For* the *Railway Reserve Feeder Reconductor to 600A - Annesbrook to Hope* there was a slight overspend due to unforeseen traffic management cost increases, project delays and additional scope.

- Reliability, safety and environment – Other reliability, safety and environment is close to target.

- System Growth is $6.9 million under target which is due to

  - the Motueka Zone Substation Upgrade project, which is underway, but is behind schedule,

  - the upgrade for the Hope Substation being delayed until the next year,

  - the 11kV Feeder Cable and CB from Brightwater Substation project being moved to future years.

- Non-network assets expenditure is $2.2 million under target with

  - the planned office extension being held up due to the delay in Tasman District Council's finalising their stormwater drainage plan. This plan has now been finalised so the project can proceed.

  - the computer hardware replacement budgeted for that year was actually scheduled for mid-2024.

Box 11: Explanatory comment on variance in actual to forecast expenditure

Operational Expenditure

General price increases have affected all categories

- Service interruptions and emergencies costs are 29% ($541,000) under target. This is due to the target allowing for more emergencies than eventuated.
- Vegetation management costs are over target by 27% ($334,000). This is a flow on effect of the July and August 2022 storms. Trees were weaken by the storms requiring additional felling and trimming.
- Routine and corrective maintenance and inspection costs are 31% ($761,000) above target. This is due to the 66kV surveying cost be irregular and access track maintenance being significantly higher than normal due to the 2022 storms.
- Asset replacement and renewal expenditure is 12% ($233,000) above target with more maintenance required again due to the 2022 storms.
- Non-network expenditure is slightly (1%, $89,000) over target.

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

For the 2023/24 regulatory year, Network Tasman forecast line charge revenues of $38.7m and actual revenues of $38.9m, a difference of approximately 0.59%.

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

Unplanned SAIDI was 128.5 for the 2023/24 year. A 33kV cable fault in Marsden Valley impacted the Marsden to Hope feeder, also tripping the Richmond feeder on 12 January

2024, resulted in widespread losses of supply to consumers in Richmond, Hope, Brightwater and Wakefield accumulating 42 SAIDI points. A further 16 SAIDI points resulted from a broken conductor on the 33kV line supplying the Takaka substation which interrupted supply to approximately 3,500 consumers on 9 February 2024.

Planned SAIDI was 104.7 for the 2023/24 year. This is less than the previous year's planned SAIDI of 154.

SAIFI targets (the average number of interruptions experienced by consumers) were not exceeded during the year. Faults per 100km of line were in line with targets. These results reflect the good condition of the network and the good state of vegetation clearance.

In some circumstances, an unplanned loss of supply event can be followed by restoration of supply and then by a successive interruption as a result of isolating the initial cause, making repairs and completing the permanent restoration of supply to all consumers. Where this occurs, Network Tasman's reported SAIFI records the initial outage and any subsequent short duration outages required to affect the restoration of supply. Network Tasman's reported SAIDI includes the customer minutes from subsequent short duration outages required to affect the restoration of supply. This treatment is different to that of previous years. For the 2023/24, Network Tasman will report two sets of SAIDI and SAIFI figures: those based on the methodology summarised above (successive interruption methodology) and a second set where the effect of subsequent short duration outages are not recorded (existing traditional methodology).

SAIDI and SAIFI were well within the Commerce Commission limits.

The percentage of faults not restored within three hours was significantly higher for 2023/24 than in previous years. Contributing factors to this were a high number of long duration feeder outages during the year during major storms and external events.

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

Network Tasman Limited has material damage cover for all zone sub-stations – buildings and associated equipment, but does not insure the wider electricity distribution network. In addition Network Tasman Limited has Public Liability, Directors and Officers insurance and Failure to Supply Cover.

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

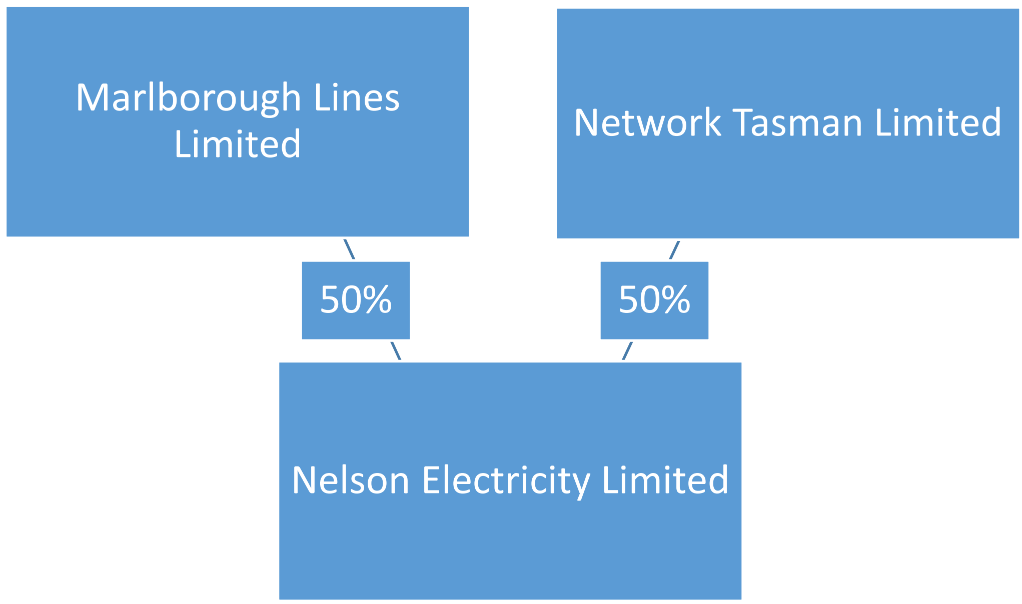
    18.2 for each error, reference to the web address where the disclosure made in accordance with clause 2.12.1 is publicly disclosed.

Box 15: Disclosure of amendment to previously disclosed information
There are no amendments to previously disclosed information.

Related Party Transactions

Related Party Relationships

Network Tasman Limited and Marlborough Lines Limited both own 50% of Nelson Electricity Limited.



Network Tasman Limited provides engineering and standby services to Nelson Electricity Limited. The charge for this service is $49,200 pa.

Network Tasman Limited also charges Nelson Electricity Limited for the following sundry charges.

	$'000
Billing administration charge	2
Insurance recovery	12
Electricity Authority levy	14
Other sundry	3
Total Annual Charge	**31**

All these charges are included in other regulated income.

Valuation Methodology

The following are the valuation methods used to provide assurance that the related party income transactions comply with 2.3.6(2)

> the value of an asset or good or service sold or supplied in the **related party transaction** must be given a value not less than if that transaction had the terms of an **arm's-length transaction**;

Nelson Electricity Limited, Network Tasman Limited and Marlborough Lines Limited are all EDBs subject to information disclosure requirements. In addition to the arm's length transaction measures below, there is a commercial tension between the parties, ensuring that they are charging a reasonable amount for the services provided to Nelson Electricity Limited.

Service Support fee for engineering and standby services.

> The fee is set at $49,200 per year. This was partly based on the number of hours estimated to be spent by Network Tasman Limited staff providing services. These hours have been reviewed and are considered a good representation of time currently spent. The hourly rates have also been reviewed and compared to current rates charged by consultants providing similar services. These rates are the same or similar. The standby portion of the charge is considered to be fair for the services Network Tasman Limited provides standby and backup support for.

Billing administration charge

> This charge is only $2,000 per year. This is an administration charge for preparing Nelson Electricity Limited's bill. Given the low value of this charge, it is considered immaterial.

Insurance recovery

> The amount of the insurance recovery ($12,000) is set out in the interconnection agreement and is reviewed annually. This is also low value charge and is not considered material.

Electricity Authority levies

The Electricity Authority bills Network Tasman Limited for Nelson Electricity Limited's levies. The amount that Network Tasman Limited on-charges Nelson Electricity Limited for these levies is the same as if the Electricity Authority were to bill Nelson Electricity Limited directly. The amount Network Tasman Limited is charged by the Electricity Authority less the amount Network Tasman Limited charges Nelson Electricity Limited is the same amount that Network Tasman Limited would pay if only their levies were charged by Electricity Authority. The rates for the Electricity Authority levies are published in the New Zealand Gazette.

Company Name	Network Tasman Limited
For Year Ended	31 March 2024

Schedule 15 Voluntary Explanatory Notes

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

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

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

   1.2 information on any substantial changes to information disclosed in relation to a prior disclosure year, as a result of final wash-ups.

2. Information in this schedule is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

3. Provide additional explanatory comment in the box below.

Box 1: Voluntary explanatory comment on disclosed information

1 (iii): Service intensity measures - Demand density links to the " Maximum coincident system demand" (row 39) instead of "Demand on system for supply to consumers' connection points" (row 41) on schedule 9e. The difference is that the line "Maximum coincident system demand" includes Nelson Electricity Limited (NEL) and "Demand on system for supply to consumers' connection points" excludes NEL. NEL is not a consumer. There are no kms included for NEL and therefore the result is currently distorted. The correct demand density should be 36kW/km.

Demand density	36

10: Report on Network Reliability–

SAIDI and SAIFI figures are now calculated under the Multi Count Approach where outages that follow the initial interruption are recorded as successive interruptions.

For the 2024, 2025 and 2026 Information Disclosures the Transitional SAIDI and SAIFI Approach which is the same method that has been used in past years is also required to be published (Sch 10(i) lines 39-43).

networktasman
Your consumer-owned electricity distributor

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Nelson, New Zealand

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Email: info@networktasman.co.nz
Website: www.networktasman.co.nz

Certification for Year-end Disclosures

Clause 2.9.2

We, Sarah Louise SMITH and Anthony Page REILLY, being directors of Network Tasman Limited certify that, having made all reasonable enquiry, to the best of our knowledge-

a) the information prepared for the purposes of clauses 2.3.1, 2.3.2, 2.4.21, 2.4.22, 2.5.1, 2.5.2, and 2.7.1 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination; and

b) the historical information used in the preparation of Schedules 8, 9a, 9b, 9c, 9d, 9e, 10, and 14 has been properly extracted from the Network Tasman 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 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.

S Smith
Sarah Louise SMITH

A P Reilly
Anthony Page REILLY

27 August 2024

Independent assurance report

To the Directors of Network Tasman 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 NZCC 2

The Network Tasman Limited (the Company) is required to disclose certain information under the Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024 NZCC 2 (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, John Mackey, 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. An engagement conducted in accordance with SAE 3100 (Revised) requires that we comply with the ISAE (NZ) 3000.

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

Key assurance matters (KAMs)

KAMs 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 matters (KAMs)	How our procedures addressed the key assurance matter
Cost allocation The Determination and the IM Determination place a requirement on the Company to allocate indirect costs between its regulated and non-regulated business. The Company has a significant investment property portfolio, a fibre network, and a smart meter network that are not part of the regulated business. The Company does not have separate management teams, or finance and administration teams for the divisions that are not part of the regulated business. Therefore, a portion of their time needs to be allocated to the regulated business. The IM Determination sets out the rules and processes for allocating non-directly attributable costs.	We obtained an understanding of the Company's cost allocation approach to allocate indirect costs to the regulated and non-regulated business. We confirmed the approach used is in accordance with the Determination and the IM Determination. The procedures we carried out, to satisfy ourselves that indirect costs were correctly allocated, included: • reconciling the regulated and unregulated financial information to the audited financial statements for the year ended 31 March 2024, to identify the costs that required allocation to the regulated business; • reviewing the costs by business unit, based on the nature of the costs and on our understanding of the business, to determine the reasonableness of the directly attributable costs by business unit; • testing a sample of invoices to ensure their classification as either directly attributable or non-directly attributable costs are appropriate and in compliance with the Determination and the IM Determination; • reviewing the Company's judgements in determining and applying appropriate methods to allocate non-directly attributable costs and assessing if the methods comply with the Determination and the IM Determination; and

<table>
<tr><th>Key assurance matters (KAMs)</th><th>How our procedures addressed the key assurance matter</th></tr>
<tr><td></td><td>testing a sample of cost allocation calculations.
Having carried out these procedures, we have no matters to report.</td></tr>
<tr><td>Accuracy of the number and duration of electricity outages

The Company has a combination of manual and automated systems to identify outages and to record the duration of outages. This outage information is used to prepare the Company’s Report on Network Reliability in schedule 10. If this information is inaccurate then the measures of the reliability of the network could be materially misstated.

This is a key assurance matter because information on the frequency and duration of outages is an important measure of the reliability of electricity supply. Relatively small inaccuracies can have a significant impact on the reliability thresholds against which the Company’s performance is assessed.

There can also be significant consequences if the Company breaches the reliability thresholds.

As the exemption related to successive interruptions reporting no longer applies, the Company is required to report a SAIDI and SAIFI value determined using the new ‘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 is also required to disclose ‘transitional’ SAIDI and SAIFI values, which are determined by using the same method applied in the 2023 disclosure year.</td><td>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:
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 included works orders for contractors, media reports, and Board minutes;
testing a sample of interruptions to supply to source records to conclude on their accuracy of calculation, and whether they were planned or unplanned, and that the cause of the interruptions was 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 “transitional” and “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.
With respect to the successive interruptions, we:
obtained and documented our understanding of the Company’s processes for recording electricity outages and their duration where an outage event results in successive interruptions of supply for the “transitional” and “multi-count” approach;</td></tr>
</table>

Key assurance matters (KAMs)	How our procedures addressed the key assurance matter
	• confirmed the processes documented for the "transitional approach" are consistent with the previous year; • identified potential incidences of successive interruptions of supply and tested a sample to ensure the SAIDI and SAIFI values have been accurately recorded for the "transitional" and "multi-count" approach; and • ensured the Company has recorded successive interruptions as an additional SAIDI and SAIFI value if restoration of supply occurs for longer than one minute. 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.
Valuation of related-party transactions at arm's-length The Determination and the IM Determination place a requirement on the Company to value related-party transactions at 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 the requirement 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 have 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 them; • reviewing the advice received by the Company from the Commerce Commission on the reasonableness of the approach adopted to determine arm's-length value for related-party transactions with its associates and joint venture; • confirming the Company followed the advice it received from the Commerce Commission on the reasonableness of the approach adopted to report sales of goods and services to its associates and joint venture; and

Key assurance matters (KAMs)	How our procedures addressed the key assurance matter
	• confirming the material accuracy of related party values disclosed, and compliance of their calculation with the Determination and the IM Determination. Having carried out these procedures, 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, 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 Default Price-Quality Path and the annual audit of the Company's financial statements and performance information, we have no relationship with, or interests in, the Company.

John Mackey
Audit New Zealand
On behalf of the Auditor-General
Christchurch, New Zealand
27 August 2024