



**EDB Information Disclosure Requirements
Information Templates
for
Schedules 1–10**

Company Name	<input type="text" value="Network Tasman Limited"/>
Disclosure Date	<input type="text" value="31 August 2022"/>
Disclosure Year (year ended)	<input type="text" value="31 March 2022"/>

Templates for Schedules 1–10 excluding 5f–5g
Template Version 4.1. Prepared 21 December 2017

Table of Contents

Schedule	Schedule name
1	ANALYTICAL RATIOS
2	REPORT ON RETURN ON INVESTMENT
3	REPORT ON REGULATORY PROFIT
4	REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)
5a	REPORT ON REGULATORY TAX ALLOWANCE
5b	REPORT ON RELATED PARTY TRANSACTIONS
5c	REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE
5d	REPORT ON COST ALLOCATIONS
5e	REPORT ON ASSET ALLOCATIONS
6a	REPORT ON CAPITAL EXPENDITURE FOR THE DISCLOSURE YEAR
6b	REPORT ON OPERATIONAL EXPENDITURE FOR THE DISCLOSURE YEAR
7	COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE
8	REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES
9a	ASSET REGISTER
9b	ASSET AGE PROFILE
9c	REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES
9d	REPORT ON EMBEDDED NETWORKS
9e	REPORT ON NETWORK DEMAND
10	REPORT ON NETWORK RELIABILITY

Company Name **Network Tasman Limited**
For Year Ended **31 March 2022**

SCHEDULE 1: ANALYTICAL RATIOS

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

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

sch ref

1(i): Expenditure metrics		Expenditure per GWh energy delivered to ICPs (\$/GWh)	Expenditure per average no. of ICPs (\$/ICP)	Expenditure per MW maximum coincident system demand (\$/MW)	Expenditure per km circuit length (\$/km)	Expenditure per MVA of capacity from EDB-owned distribution transformers (\$/MVA)
7						
8						
9	Operational expenditure	18,357	288	92,211	3,246	25,962
10	Network	10,018	157	50,324	1,771	14,169
11	Non-network	8,339	131	41,888	1,474	11,793
12						
13	Expenditure on assets	18,342	287	92,134	3,243	25,940
14	Network	17,655	277	88,683	3,122	24,968
15	Non-network	687	11	3,451	121	972
16						
17	1(ii): Revenue metrics					
18						
19	Total consumer line charge revenue	58,542	917			
20	Standard consumer line charge revenue	63,765	827			
21	Non-standard consumer line charge revenue	33,366	934,397			
22						
23	1(iii): Service intensity measures					
24						
25	Demand density	40				Maximum coincident system demand per km of circuit length (for supply) (kW/km)
26	Volume density	177				Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)
27	Connection point density	11				Average number of ICPs per km of circuit length (for supply) (ICPs/km)
28	Energy intensity	15,665				Total energy delivered to ICPs per average number of ICPs (kWh/ICP)
29						
30	1(iv): Composition of regulatory income					
31						
32						
33	Operational expenditure			11,969	31.72%	
34	Pass-through and recoverable costs excluding financial incentives and wash-ups			13,398	35.51%	
35	Total depreciation			7,346	19.47%	
36	Total revaluations			12,221	32.39%	
37	Regulatory tax allowance			2,022	5.36%	
38	Regulatory profit/(loss) including financial incentives and wash-ups			15,214	40.33%	
39	Total regulatory income			37,729		
40	1(v): Reliability					
41						
42	Interruption rate			8.70		Interruptions per 100 circuit km

Company Name **Network Tasman Limited**
 For Year Ended **31 March 2022**

SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

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

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

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sch ref

2(i): Return on Investment		CY-2	CY-1	Current Year CY
		31 Mar 20	31 Mar 21	31 Mar 22
		%	%	%
7	ROI – comparable to a post tax WACC			
8				
9	Reflecting all revenue earned	3.91%	2.82%	8.30%
10	Excluding revenue earned from financial incentives	2.21%	2.82%	8.30%
11	Excluding revenue earned from financial incentives and wash-ups	2.34%	2.82%	8.39%
12				
13				
14	Mid-point estimate of post tax WACC	4.27%	3.72%	3.52%
15	25th percentile estimate	3.59%	3.04%	2.84%
16	75th percentile estimate	4.95%	4.40%	4.20%
17				
18				
19	ROI – comparable to a vanilla WACC			
20	Reflecting all revenue earned	4.33%	3.16%	8.60%
21	Excluding revenue earned from financial incentives	2.63%	3.16%	8.60%
22	Excluding revenue earned from financial incentives and wash-ups	2.77%	3.16%	8.69%
23				
24	WACC rate used to set regulatory price path	7.19%	4.57%	4.57%
25				
26	Mid-point estimate of vanilla WACC	4.69%	4.05%	3.82%
27	25th percentile estimate	4.01%	3.37%	3.14%
28	75th percentile estimate	5.37%	4.73%	4.50%
29				
30	2(ii): Information Supporting the ROI			
31				
32	Total opening RAB value	177,306		
33	plus Opening deferred tax	(3,213)		
34	Opening RIV		174,093	
35				
36	Line charge revenue		38,170	
37				
38	Expenses cash outflow	25,367		
39	add Assets commissioned	10,506		
40	less Asset disposals	1,050		
41	add Tax payments	1,479		
42	less Other regulated income	(441)		
43	Mid-year net cash outflows		36,743	
44				
45	Term credit spread differential allowance		–	
46				
47	Total closing RAB value	191,545		
48	less Adjustment resulting from asset allocation	(92)		
49	less Lost and found assets adjustment	–		
50	plus Closing deferred tax	(3,756)		
51	Closing RIV		187,881	
52				
53	ROI – comparable to a vanilla WACC			8.60%
54				
55	Leverage (%)			42%
56	Cost of debt assumption (%)			2.55%
57	Corporate tax rate (%)			28%
58				
59	ROI – comparable to a post tax WACC			8.30%
60				

Company Name **Network Tasman Limited**
 For Year Ended **31 March 2022**

SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

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

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

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2(iii): Information Supporting the Monthly ROI

61										
62										
63	Opening RIV								N/A	
64										
65										
66		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	-	-	-	-	-	-	-	-	
80										
81	Tax payments								N/A	
82										
83	Term credit spread differential allowance								N/A	
84										
85	Closing RIV								N/A	
86										
87										
88	Monthly ROI – comparable to a vanilla WACC								N/A	
89										
90	Monthly ROI – comparable to a post tax WACC								N/A	
91										
92	2(iv): Year-End ROI Rates for Comparison Purposes									
93										
94	Year-end ROI – comparable to a vanilla WACC								8.60%	
95										
96	Year-end ROI – comparable to a post tax WACC								8.30%	
97										
98	<i>* 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.</i>									
99										
100	2(v): Financial Incentives and Wash-Ups									
101										
102	Net recoverable costs allowed under incremental rolling incentive scheme								-	
103	Purchased assets – avoided transmission charge								-	
104	Energy efficiency and demand incentive allowance								-	
105	Quality incentive adjustment								(3)	
106	Other financial incentives								-	
107	Financial incentives								(3)	
108										
109	Impact of financial incentives on ROI								-0.00%	
110										
111	Input methodology claw-back								-	
112	CPP application recoverable costs								-	
113	Catastrophic event allowance								-	
114	Capex wash-up adjustment								(212)	
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								(212)	
120										
121	Impact of wash-up costs on ROI								-0.09%	

Company Name **Network Tasman Limited**
 For Year Ended **31 March 2022**

SCHEDULE 3: REPORT ON REGULATORY PROFIT

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

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sch ref

7	3(i): Regulatory Profit	(\$000)
8	Income	
9	Line charge revenue	38,170
10	plus Gains / (losses) on asset disposals	(613)
11	plus Other regulated income (other than gains / (losses) on asset disposals)	172
12		
13	Total regulatory income	37,729
14	Expenses	
15	less Operational expenditure	11,969
16		
17	less Pass-through and recoverable costs excluding financial incentives and wash-ups	13,398
18		
19	Operating surplus / (deficit)	12,362
20		
21	less Total depreciation	7,346
22		
23	plus Total revaluations	12,221
24		
25	Regulatory profit / (loss) before tax	17,236
26		
27	less Term credit spread differential allowance	-
28		
29	less Regulatory tax allowance	2,022
30		
31	Regulatory profit/(loss) including financial incentives and wash-ups	15,214
32		
33	3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups	(\$000)
34	Pass through costs	
35	Rates	166
36	Commerce Act levies	113
37	Industry levies	157
38	CPP specified pass through costs	-
39	Recoverable costs excluding financial incentives and wash-ups	
40	Electricity lines service charge payable to Transpower	9,935
41	Transpower new investment contract charges	1,244
42	System operator services	-
43	Distributed generation allowance	1,783
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	13,398
47		

Company Name **Network Tasman Limited**
 For Year Ended **31 March 2022**

SCHEDULE 3: REPORT ON REGULATORY PROFIT

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

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sch ref

		(\$000)	
		CY-1	CY
		31 Mar 21	31 Mar 22
48	3(iii): Incremental Rolling Incentive Scheme		
49			
50			
51	Allowed controllable opex	-	-
52	Actual controllable opex	-	-
53			
54	Incremental change in year		-
55			
		Previous years' incremental change	Previous years' incremental change adjusted for inflation
56			
57	CY-5 31 Mar 17	-	-
58	CY-4 31 Mar 18	-	-
59	CY-3 31 Mar 19	-	-
60	CY-2 31 Mar 20	-	-
61	CY-1 31 Mar 21	-	-
62	Net incremental rolling incentive scheme		-
63			
64	Net recoverable costs allowed under incremental rolling incentive scheme		-
65	3(iv): Merger and Acquisition Expenditure		
70			(\$000)
66	Merger and acquisition expenditure		-
67			
68	<i>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)</i>		
69	3(v): Other Disclosures		
70			(\$000)
71	Self-insurance allowance		-

Company Name **Network Tasman Limited**
 For Year Ended **31 March 2022**

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

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

sch ref

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

	for year ended				
	RAB 31 Mar 18 (\$000)	RAB 31 Mar 19 (\$000)	RAB 31 Mar 20 (\$000)	RAB 31 Mar 21 (\$000)	RAB 31 Mar 22 (\$000)
Total opening RAB value	164,637	165,522	165,472	174,395	177,306
less Total depreciation	6,954	6,807	6,984	6,984	7,346
plus Total revaluations	1,808	2,452	4,187	2,650	12,221
plus Assets commissioned	6,386	6,557	12,075	8,066	10,506
less Asset disposals	355	393	332	847	1,050
plus Lost and found assets adjustment	-	-	-	-	-
plus Adjustment resulting from asset allocation	-	(1,859)	(23)	26	(92)
Total closing RAB value	165,522	165,472	174,395	177,306	191,545

4(ii): Unallocated Regulatory Asset Base

	Unallocated RAB *		RAB	
	(\$000)	(\$000)	(\$000)	(\$000)
Total opening RAB value		179,105		177,306
less Total depreciation		7,599		7,346
plus Total revaluations		12,345		12,221
plus Assets commissioned (other than below)	10,543		10,506	
Assets acquired from a regulated supplier	-		-	
Assets acquired from a related party	-		-	
Assets commissioned		10,543		10,506
less Asset disposals (other than below)	1,051		1,050	
Asset disposals to a regulated supplier	-		-	
Asset disposals to a related party	-		-	
Asset disposals		1,051		1,050
plus Lost and found assets adjustment		-		-
plus Adjustment resulting from asset allocation				(92)
Total closing RAB value		193,343		191,545

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

Company Name **Network Tasman Limited**
 For Year Ended **31 March 2022**

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

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

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

CPI _t	1,142
CPI _{t-4}	1,068
Revaluation rate (%)	6.93%

	Unallocated RAB *		RAB	
	(\$000)	(\$000)	(\$000)	(\$000)
Total opening RAB value	179,105		177,306	
less Opening value of fully depreciated, disposed and lost assets	942		934	
Total opening RAB value subject to revaluation	178,163		176,372	
Total revaluations		12,345		12,221

4(iv): Roll Forward of Works Under Construction

	Unallocated works under construction		Allocated works under construction	
Works under construction—preceding disclosure year		7,860		7,941
plus Capital expenditure	11,585		11,585	
less Assets commissioned	10,543		10,506	
plus Adjustment resulting from asset allocation			(121)	
Works under construction - current disclosure year		8,902		8,899
Highest rate of capitalised finance applied				-

Company Name **Network Tasman Limited**
 For Year Ended **31 March 2022**

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

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

sch ref

76 **4(v): Regulatory Depreciation**

	Unallocated RAB *		RAB	
	(\$000)	(\$000)	(\$000)	(\$000)
79 Depreciation - standard	6,978		6,874	
80 Depreciation - no standard life assets	621		472	
81 Depreciation - modified life assets	-		-	
82 Depreciation - alternative depreciation in accordance with CPP	-		-	
83 Total depreciation		7,599		7,346

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

(\$000 unless otherwise specified)

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

* include additional rows if needed

96 **4(vii): Disclosure by Asset Category**

(\$000 unless otherwise specified)

	Subtransmission lines	Subtransmission cables	Zone substations	Distribution and LV lines	Distribution and LV cables	Distribution substations and transformers	Distribution switchgear	Other network assets	Non-network assets	Total
99 Total opening RAB value	8,013	10,530	25,590	25,843	55,961	26,068	9,886	11,869	3,546	177,306
100 <i>less</i> Total depreciation	294	231	738	1,925	1,550	1,139	367	626	476	7,346
101 <i>plus</i> Total revaluations	555	733	1,774	1,790	3,867	1,806	663	808	225	12,221
102 <i>plus</i> Assets commissioned	388	247	1,572	2,238	2,439	1,852	421	1,067	282	10,506
103 <i>less</i> Asset disposals	2	-	-	177	16	255	365	114	121	1,050
104 <i>plus</i> Lost and found assets adjustment	-	-	-	-	-	-	-	-	-	-
105 <i>plus</i> Adjustment resulting from asset allocation	-	-	-	(13)	-	-	-	(2)	(77)	(92)
106 <i>plus</i> Asset category transfers	(3)	55	7	3	99	21	(12)	(170)	-	-
107 Total closing RAB value	8,657	11,334	28,205	27,759	60,800	28,353	10,226	12,832	3,379	191,545
109 Asset Life										
110 Weighted average remaining asset life	39.3	52.0	34.3	54.1	48.0	46.4	44.5	17.0	20.8	(years)
111 Weighted average expected total asset life	62.0	63.3	47.8	77.2	66.5	66.3	57.5	35.6	27.7	(years)

Company Name **Network Tasman Limited**
 For Year Ended **31 March 2022**

SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

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

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

sch ref

		(\$000)	
7	5a(i): Regulatory Tax Allowance		
8	Regulatory profit / (loss) before tax		17,236
9			
10	<i>plus</i> Income not included in regulatory profit / (loss) before tax but taxable	-	*
11	Expenditure or loss in regulatory profit / (loss) before tax but not deductible	62	*
12	Amortisation of initial differences in asset values	3,238	
13	Amortisation of revaluations	747	
14			4,047
15			
16	<i>less</i> Total revaluations	12,221	
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	1,841	
21			14,062
22			
23	Regulatory taxable income		7,222
24			
25	<i>less</i> Utilised tax losses	-	
26	Regulatory net taxable income		7,222
27			
28	Corporate tax rate (%)	28%	
29	Regulatory tax allowance		2,022

* Workings to be provided in Schedule 14

5a(ii): Disclosure of Permanent Differences

In Schedule 14, Box 5, provide descriptions and workings of items recorded in the asterisked categories in Schedule 5a(i).

		(\$000)	
34	5a(iii): Amortisation of Initial Difference in Asset Values		
35			
36	Opening unamortised initial differences in asset values	72,402	
37	<i>less</i> Amortisation of initial differences in asset values	3,238	
38	<i>plus</i> Adjustment for unamortised initial differences in assets acquired	-	
39	<i>less</i> Adjustment for unamortised initial differences in assets disposed	14	
40	Closing unamortised initial differences in asset values		69,149
41			
42	Opening weighted average remaining useful life of relevant assets (years)		22
43			

Company Name **Network Tasman Limited**
 For Year Ended **31 March 2022**

SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

This schedule requires information on the calculation of the regulatory tax allowance. This information is used to calculate regulatory profit/loss in Schedule 3 (regulatory profit). EDBs must provide explanatory commentary on the information disclosed in this schedule, in Schedule 14 (Mandatory Explanatory Notes). This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 130.

sch ref

44	5a(iv): Amortisation of Revaluations		(\$000)
45			
46	Opening sum of RAB values without revaluations	157,181	
47			
48	Adjusted depreciation	6,599	
49	Total depreciation	7,346	
50	Amortisation of revaluations		747
51			
52	5a(v): Reconciliation of Tax Losses		(\$000)
53			
54	Opening tax losses	-	
55	plus Current period tax losses	-	
56	less Utilised tax losses	-	
57	Closing tax losses		-
58	5a(vi): Calculation of Deferred Tax Balance		(\$000)
59			
60	Opening deferred tax	(3,213)	
61			
62	plus Tax effect of adjusted depreciation	1,848	
63			
64	less Tax effect of tax depreciation	1,693	
65			
66	plus Tax effect of other temporary differences*	(72)	
67			
68	less Tax effect of amortisation of initial differences in asset values	907	
69			
70	plus Deferred tax balance relating to assets acquired in the disclosure year	-	
71			
72	less Deferred tax balance relating to assets disposed in the disclosure year	(241)	
73			
74	plus Deferred tax cost allocation adjustment	40	
75			
76	Closing deferred tax		(3,756)
77			
78	5a(vii): Disclosure of Temporary Differences		
79	<i>In Schedule 14, Box 6, provide descriptions and workings of items recorded in the asterisked category in Schedule 5a(vi) (Tax effect of other temporary differences).</i>		
80			
81	5a(viii): Regulatory Tax Asset Base Roll-Forward		
82			(\$000)
83	Opening sum of regulatory tax asset values	71,664	
84	less Tax depreciation	6,047	
85	plus Regulatory tax asset value of assets commissioned	10,372	
86	less Regulatory tax asset value of asset disposals	190	
87	plus Lost and found assets adjustment	-	
88	plus Adjustment resulting from asset allocation	53	
89	plus Other adjustments to the RAB tax value	-	
90	Closing sum of regulatory tax asset values		75,852

Company Name **Network Tasman Limited**
 For Year Ended **31 March 2022**

SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

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

sch ref

		(\$000)	(\$000)
7	5b(i): Summary—Related Party Transactions		
8	Total regulatory income		81
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	-	
19	Operational expenditure		-
20	Consumer connection	-	
21	System growth	-	
22	Asset replacement and renewal (capex)	-	
23	Asset relocations	-	
24	Quality of supply	-	
25	Legislative and regulatory	-	
26	Other reliability, safety and environment	-	
27	Expenditure on non-network assets		-
28	Expenditure on assets		-
29	Cost of financing		-
30	Value of capital contributions		-
31	Value of vested assets		-
32	Capital Expenditure		-
33	Total expenditure		-
34			
35	Other related party transactions		-

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

	Name of related party	Nature of opex or capex service provided	Total value of transactions (\$000)
37			
38	-	[Select one]	-
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	Total value of related party transactions		-

* include additional rows if needed

Company Name **Network Tasman Limited**
 For Year Ended **31 March 2022**

SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

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

sch ref

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

Issuing party	Issue date	Pricing date	Original tenor (in years)	Coupon rate (%)	Book value at issue date (NZD)	Book value at date of financial statements (NZD)	Term Credit Spread Difference	Debt issue cost readjustment
N/A								
* include additional rows if needed						-	-	-

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

Gross term credit spread differential								
Total book value of interest bearing debt								
Leverage			42%					
Average opening and closing RAB values								
Attribution Rate (%)								
Term credit spread differential allowance								

Company Name **Network Tasman Limited**
 For Year Ended **31 March 2022**

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref

7 5d(i): Operating Cost Allocations

		Value allocated (\$000s)				
		Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase (\$000s)
10	Service interruptions and emergencies					
11	Directly attributable		1,243			
12	Not directly attributable	-	-	-	-	-
13	Total attributable to regulated service		1,243			
14	Vegetation management					
15	Directly attributable		1,203			
16	Not directly attributable	-	-	-	-	-
17	Total attributable to regulated service		1,203			
18	Routine and corrective maintenance and inspection					
19	Directly attributable		2,260			
20	Not directly attributable	-	-	-	-	-
21	Total attributable to regulated service		2,260			
22	Asset replacement and renewal					
23	Directly attributable		1,826			
24	Not directly attributable	-	-	-	-	-
25	Total attributable to regulated service		1,826			
26	System operations and network support					
27	Directly attributable		3,111			
28	Not directly attributable	-	-	-	-	-
29	Total attributable to regulated service		3,111			
30	Business support					
31	Directly attributable		636			
32	Not directly attributable	-	1,690	873	2,563	-
33	Total attributable to regulated service		2,326			
34						
35	Operating costs directly attributable		10,279			
36	Operating costs not directly attributable	-	1,690	873	2,563	-
37	Operational expenditure		11,969			

Company Name **Network Tasman Limited**
 For Year Ended **31 March 2022**

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref

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5d(ii): Other Cost Allocations

		(\$000)
Pass through and recoverable costs		
Pass through costs		
Directly attributable		432
Not directly attributable		4
Total attributable to regulated service		436
Recoverable costs		
Directly attributable		12,961
Not directly attributable		-
Total attributable to regulated service		12,961

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

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

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

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

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

Company Name **Network Tasman Limited**
 For Year Ended **31 March 2022**

SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

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

sch ref

7 5e(i): Regulated Service Asset Values		Value allocated (\$000s) Electricity distribution services
8		
9		
10	Subtransmission lines	
11	Directly attributable	8,657
12	Not directly attributable	-
13	Total attributable to regulated service	8,657
14	Subtransmission cables	
15	Directly attributable	11,334
16	Not directly attributable	-
17	Total attributable to regulated service	11,334
18	Zone substations	
19	Directly attributable	28,205
20	Not directly attributable	-
21	Total attributable to regulated service	28,205
22	Distribution and LV lines	
23	Directly attributable	25,637
24	Not directly attributable	2,122
25	Total attributable to regulated service	27,759
26	Distribution and LV cables	
27	Directly attributable	60,800
28	Not directly attributable	-
29	Total attributable to regulated service	60,800
30	Distribution substations and transformers	
31	Directly attributable	28,353
32	Not directly attributable	-
33	Total attributable to regulated service	28,353
34	Distribution switchgear	
35	Directly attributable	10,226
36	Not directly attributable	-
37	Total attributable to regulated service	10,226
38	Other network assets	
39	Directly attributable	12,769
40	Not directly attributable	62
41	Total attributable to regulated service	12,831
42	Non-network assets	
43	Directly attributable	1,169
44	Not directly attributable	2,211
45	Total attributable to regulated service	3,380
46		
47	Regulated service asset value directly attributable	187,150
48	Regulated service asset value not directly attributable	4,395
49	Total closing RAB value	191,545

51 5e(ii): Changes in Asset Allocations* †		(\$000)	
		CY-1	Current Year (CY)
52			
53	Change in asset value allocation 1		
54	Asset category		
55	Original allocator or line items		
56	New allocator or line items		
57			
58	Rationale for change		
59			
60			
61			
62	Change in asset value allocation 2		
63	Asset category		
64	Original allocator or line items		
65	New allocator or line items		
66			
67	Rationale for change		
68			
69			
70			
71	Change in asset value allocation 3		
72	Asset category		
73	Original allocator or line items		
74	New allocator or line items		
75			
76	Rationale for change		
77			
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* a change in asset allocation must be completed for each allocator or component change that has occurred in the disclosure year. A movement in an allocator metric is not a change in allocator or compor
 † include additional rows if needed

Company Name **Network Tasman Limited**
 For Year Ended **31 March 2022**

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

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

sch ref

		(\$000)	(\$000)
7	6a(i): Expenditure on Assets		
8	Consumer connection		763
9	System growth		2,962
10	Asset replacement and renewal		6,686
11	Asset relocations		41
12	Reliability, safety and environment:		
13	Quality of supply	523	
14	Legislative and regulatory	-	
15	Other reliability, safety and environment	536	
16	Total reliability, safety and environment		1,059
17	Expenditure on network assets		11,511
18	Expenditure on non-network assets		448
19			
20	Expenditure on assets		11,959
21	plus Cost of financing		-
22	less Value of capital contributions		642
23	plus Value of vested assets		268
24			
25	Capital expenditure		11,585
26	6a(ii): Subcomponents of Expenditure on Assets (where known)		(\$000)
27	Energy efficiency and demand side management, reduction of energy losses		63
28	Overhead to underground conversion		6
29	Research and development		-
30	6a(iii): Consumer Connection		
31	<i>Consumer types defined by EDB*</i>	(\$000)	(\$000)
32	Consumers 20kVA and less	283	
33	Consumers greater than 20kVA	480	
34		-	
35		-	
36		-	
37	<i>* include additional rows if needed</i>		
38	Consumer connection expenditure		763
39			
40	less Capital contributions funding consumer connection expenditure	3	
41	Consumer connection less capital contributions		760
42	6a(iv): System Growth and Asset Replacement and Renewal		
43		System Growth	Asset Replacement and Renewal
44		(\$000)	(\$000)
45	Subtransmission	(39)	261
46	Zone substations	-	1,952
47	Distribution and LV lines	1,688	285
48	Distribution and LV cables	833	470
49	Distribution substations and transformers	335	150
50	Distribution switchgear	6	54
51	Other network assets	139	3,514
52	System growth and asset replacement and renewal expenditure	2,962	6,686
53	less Capital contributions funding system growth and asset replacement and renewal	470	23
54	System growth and asset replacement and renewal less capital contributions	2,492	6,663
55			
56	6a(v): Asset Relocations		
57	<i>Project or programme*</i>	(\$000)	(\$000)
58		-	
59		-	
60		-	
61		-	
62		-	
63	<i>* include additional rows if needed</i>		
64	All other projects or programmes - asset relocations	41	
65	Asset relocations expenditure		41
66	less Capital contributions funding asset relocations	146	
67	Asset relocations less capital contributions		(105)

Company Name **Network Tasman Limited**
 For Year Ended **31 March 2022**

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

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

sch ref

68				
69	6a(vi): Quality of Supply			
70	Project or programme*	(\$000)	(\$000)	
71		-		
72		-		
73		-		
74		-		
75		-		
76	* include additional rows if needed			
77	All other projects programmes - quality of supply	523		
78	Quality of supply expenditure		523	
79	less Capital contributions funding quality of supply	-		
80	Quality of supply less capital contributions		523	
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	439		
96		-		
97		-		
98		-		
99		-		
100	* include additional rows if needed			
101	All other projects or programmes - other reliability, safety and environment	97		
102	Other reliability, safety and environment expenditure		536	
103	less Capital contributions funding other reliability, safety and environment	-		
104	Other reliability, safety and environment less capital contributions		536	
105				
106	6a(ix): Non-Network Assets			
107	Routine expenditure			
108	Project or programme*	(\$000)	(\$000)	
109	Land & Buildings	62		
110	IT	353		
111	Vehicles, Plant & Equipment	33		
112		-		
113		-		
114	* include additional rows if needed			
115	All other projects or programmes - routine expenditure	-		
116	Routine expenditure		448	
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		448	

Company Name **Network Tasman Limited**
 For Year Ended **31 March 2022**

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

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

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

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

sch ref

		(\$000)	(\$000)
7	6b(i): Operational Expenditure		
8	Service interruptions and emergencies	1,243	
9	Vegetation management	1,203	
10	Routine and corrective maintenance and inspection	2,260	
11	Asset replacement and renewal	1,826	
12	Network opex		6,532
13	System operations and network support	3,111	
14	Business support	2,326	
15	Non-network opex		5,437
16			
17	Operational expenditure		11,969
18	6b(ii): Subcomponents of Operational Expenditure (where known)		
19	Energy efficiency and demand side management, reduction of energy losses		161
20	Direct billing*		-
21	Research and development		-
22	Insurance		386
23	* Direct billing expenditure by suppliers that directly bill the majority of their consumers		

Company Name **Network Tasman Limited**For Year Ended **31 March 2022****SCHEDULE 7: COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE**

This schedule compares actual revenue and expenditure to the previous forecasts that were made for the disclosure year. Accordingly, this schedule requires the forecast revenue and expenditure information from previous disclosures to be inserted.

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

sch ref

7	7(i): Revenue	Target (\$000) ¹	Actual (\$000)	% variance
8	Line charge revenue	37,352	38,170	2%
9	7(ii): Expenditure on Assets	Forecast (\$000) ²	Actual (\$000)	% variance
10	Consumer connection	640	763	19%
11	System growth	5,103	2,962	(42%)
12	Asset replacement and renewal	6,533	6,686	2%
13	Asset relocations	500	41	(92%)
14	Reliability, safety and environment:			
15	Quality of supply	2,745	523	(81%)
16	Legislative and regulatory	700	–	(100%)
17	Other reliability, safety and environment	560	536	(4%)
18	Total reliability, safety and environment	4,005	1,059	(74%)
19	Expenditure on network assets	16,781	11,511	(31%)
20	Expenditure on non-network assets	861	448	(48%)
21	Expenditure on assets	17,642	11,959	(32%)
22	7(iii): Operational Expenditure			
23	Service interruptions and emergencies	1,098	1,243	13%
24	Vegetation management	1,245	1,203	(3%)
25	Routine and corrective maintenance and inspection	2,400	2,260	(6%)
26	Asset replacement and renewal	2,155	1,826	(15%)
27	Network opex	6,898	6,532	(5%)
28	System operations and network support	3,205	3,111	(3%)
29	Business support	2,265	2,326	3%
30	Non-network opex	5,470	5,437	(1%)
31	Operational expenditure	12,368	11,969	(3%)
32	7(iv): Subcomponents of Expenditure on Assets (where known)			
33	Energy efficiency and demand side management, reduction of energy losses	–	63	–
34	Overhead to underground conversion	500	6	(99%)
35	Research and development	–	–	–
36				
37	7(v): Subcomponents of Operational Expenditure (where known)			
38	Energy efficiency and demand side management, reduction of energy losses	78	161	106%
39	Direct billing	–	–	–
40	Research and development	–	–	–
41	Insurance	393	386	(2%)

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

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 2022**
 Network / Sub-Network Name **Network Tasman Limited**

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

8(i): Billed Quantities by Price Component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)
--	---	---	--	---

0S	Streetlamps	Standard	–	1,809
0UNM	Unmetered Supplies	Standard	70	13
1RL	15 kVA Capacity	Standard	18,663	106,960
1RS	15 kVA Capacity	Standard	16,147	146,141
1GL	15 kVA Capacity	Standard	3,693	21,270
2	20 - 150 kVA Capacity	Standard	2,800	97,624
2HLFC	or 30 kVA Capacity	Standard	–	15
2LLFC	150kVA Capacity	Standard	55	439
HLF	150kVA Capacity	Standard	4	9,326
3.1	3000kVA	Standard	4	9,629
3.3	3000kVA	Standard	6	8,840
3.4	3000kVA	Standard	174	126,925
3.5	3000kVA	Standard	2	10,994
6.1	> 3000,	Non-standard	1	95,485
6.2	> 3000,	Non-standard	1	16,469
CB	Cobb River Hydro	Non-standard	1	32
MAT	Matiri Hydro	Non-standard	1	31
Connections	–	Standard	–	–
Solar Connections	–	Standard	–	–
0	–	[Select one]	–	–

Add extra rows for additional consumer groups or price category codes as necessary

Standard consumer totals	41,618	539,985
Non-standard consumer totals	4	112,017
Total for all consumers	41,622	652,002

Billed quantities by price component

Price component	OSTL	0UNM	1RLANY	1RLDAY	1RLNIT	1RLWSR	1RLGEN	1RSANY
	Watts	day	kWh	kWh	kWh	kWh	kWh	kWh

430,740	–	–	–	–	–	–	–	–
–	70	–	–	–	–	–	–	–
–	–	74,789	2,146	2,072	27,953	2,078	–	–
–	–	–	–	–	–	–	106,271	–
–	–	–	–	–	–	–	–	–
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430,740	70	74,789	2,146	2,072	27,953	2,078	106,271
–	–	–	–	–	–	–	–
430,740	70	74,789	2,146	2,072	27,953	2,078	106,271

SCHEDULE 8: REPORT ON BILLED QUANTITIES

This schedule requires the billed quantities and associated line charge re in each consumer group or price category code, and the energy delivered

sch ref

8(i): Billed Quantities by Price Component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	1RSDAY	1RSNIT	1RSWSR	1RSGEN	1GLANY	1GLDAY	1GLNIT	1GLWSR	1GLGEN	2ANY	2DAY	2NIT	2WSR	2GEN
			kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh
0S	Streetlamps	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
0UNM	Unmetered Supplies	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1RL	15 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1RS	15 kVA Capacity	Standard	2,606	3,065	34,199	1,427	-	-	-	-	-	-	-	-	-	-
1GL	15 kVA Capacity	Standard	-	-	-	-	18,384	819	455	1,612	108	-	-	-	-	-
2	20 - 150 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	67,979	18,575	7,827	3,243	802
2HLFC	or 30 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2LLFC	150kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HLF	150kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.1	3000kVA	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.3	3000kVA	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.4	3000kVA	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.5	3000kVA	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6.1	> 3000,	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6.2	> 3000,	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CB	Cobb River Hydro	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MAT	Matiri Hydro	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Connections	-	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar Connections	-	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
0	-	[Select one]	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<i>Add extra rows for additional consumer groups or price categories</i>																
Standard consumer totals			2,606	3,065	34,199	1,427	18,384	819	455	1,612	108	67,979	18,575	7,827	3,243	802
Non-standard consumer totals			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total for all consumers			2,606	3,065	34,199	1,427	18,384	819	455	1,612	108	67,979	18,575	7,827	3,243	802

SCHEDULE 8: REPORT ON BILLED QUANTITIES

This schedule requires the billed quantities and associated line charge re in each consumer group or price category code, and the energy delivered

sch ref

8(i): Billed Quantities by Price Component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	2LANY	2LDAY	2LNIT	2LWSR	2LGEN	2HANY	2HDAY	2HNIT	2HWSR	2HGEN	HLFANY	HLFDAY	HLFNIT	HLFWSR
			kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh
0S	Streetlamps	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
0UNM	Unmetered Supplies	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1RL	15 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1RS	15 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1GL	15 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	20 - 150 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2HLFC	or 30 kVA Capacity	Standard	-	-	-	-	-	10	-	-	5	-	-	-	-	-
2LLFC	150kVA Capacity	Standard	344	32	17	46	4	-	-	-	-	-	-	-	-	-
HLF	150kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	4,490	3,417	1,362	57
3.1	3000kVA	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.3	3000kVA	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.4	3000kVA	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.5	3000kVA	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6.1	> 3000,	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6.2	> 3000,	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CB	Cobb River Hydro	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MAT	Matiri Hydro	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Connections	-	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar Connections	-	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
0	-	[Select one]	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Add extra rows for additional consumer groups or price categories																
Standard consumer totals			344	32	17	46	4	10	-	-	5	-	4,490	3,417	1,362	57
Non-standard consumer totals			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total for all consumers			344	32	17	46	4	10	-	-	5	-	4,490	3,417	1,362	57

SCHEDULE 8: REPORT ON BILLED QUANTITIE

This schedule requires the billed quantities and associated line charge re in each consumer group or price category code, and the energy delivere

sch ref

8(i): Billed Quantities by Price Component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	HLFGEN	1RL	1RS	1GL	2	2HLFC	2LLFC	HLF	AnyDem31	AnyDem33	AnyDem34	AnyDem35	WinDem	kVAr
			kWh	Daily	Daily	Daily	Capacity	Daily	Daily	kVA	kVA	kVA	kVA	kVA	kW	kVAr
0S	Streetlamps	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
0UNM	Unmetered Supplies	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1RL	15 kVA Capacity	Standard	-	18,798	-	-	-	-	-	-	-	-	-	-	-	-
1RS	15 kVA Capacity	Standard	-	-	16,178	-	-	-	-	-	-	-	-	-	-	-
1GL	15 kVA Capacity	Standard	-	-	-	3,683	-	-	-	-	-	-	-	-	-	-
2	20 - 150 kVA Capacity	Standard	-	-	-	-	127,795	-	-	-	-	-	-	-	-	-
2HLFC	or 30 kVA Capacity	Standard	-	-	-	-	-	5	-	-	-	-	-	-	-	-
2LLFC	150kVA Capacity	Standard	-	-	-	-	-	-	166	-	-	-	-	-	-	-
HLF	150kVA Capacity	Standard	19	-	-	-	-	-	-	3,115	-	-	-	-	-	-
3.1	3000kVA	Standard	-	-	-	-	-	-	-	-	2,198	-	-	-	1,298	-
3.3	3000kVA	Standard	-	-	-	-	-	-	-	-	-	2,351	-	-	1,064	-
3.4	3000kVA	Standard	-	-	-	-	-	-	-	-	-	-	47,918	-	19,856	131
3.5	3000kVA	Standard	-	-	-	-	-	-	-	-	-	-	-	4,175	2,208	-
6.1	> 3000,	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6.2	> 3000,	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CB	Cobb River Hydro	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MAT	Matiri Hydro	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Connections	-	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar Connections	-	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
0	-	[Select one]	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard consumer totals			19	18,798	16,178	3,683	127,795	5	166	3,115	2,198	2,351	47,918	4,175	24,427	131
Non-standard consumer totals			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total for all consumers			19	18,798	16,178	3,683	127,795	5	166	3,115	2,198	2,351	47,918	4,175	24,427	131

Add extra rows for additional consumer groups or price cate

SCHEDULE 8: REPORT ON BILLED QUANTITIES

This schedule requires the billed quantities and associated line charge re in each consumer group or price category code, and the energy delivered

sch ref

8(i): Billed Quantities by Price Component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	SD31	SN31	WD31	WN31	SD33	SN33	WD33	WN33	SD34	SN34	WD34	WN34	SD35	SN35		
			kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh
0S	Streetlamps	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
0UNM	Unmetered Supplies	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
1RL	15 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
1RS	15 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
1GL	15 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
2	20 - 150 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
2HLFC	or 30 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
2LLFC	150kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
HLF	150kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
3.1	3000kVA	Standard	3,956	1,634	2,865	1,174	-	-	-	-	-	-	-	-	-	-	-	
3.3	3000kVA	Standard	-	-	-	-	3,905	1,747	2,250	938	-	-	-	-	-	-	-	
3.4	3000kVA	Standard	-	-	-	-	-	-	-	-	52,411	18,939	40,473	15,102	-	-	-	
3.5	3000kVA	Standard	-	-	-	-	-	-	-	-	-	-	-	-	4,272	1,901	-	
6.1	> 3000,	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
6.2	> 3000,	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
CB	Cobb River Hydro	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
MAT	Matiri Hydro	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Connections	-	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Solar Connections	-	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
0	-	[Select one]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Standard consumer totals			3,956	1,634	2,865	1,174	3,905	1,747	2,250	938	52,411	18,939	40,473	15,102	4,272	1,901	-	-
Non-standard consumer totals			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total for all consumers			3,956	1,634	2,865	1,174	3,905	1,747	2,250	938	52,411	18,939	40,473	15,102	4,272	1,901	-	-

Add extra rows for additional consumer groups or price categories

SCHEDULE 8: REPORT ON BILLED QUANTITIE

This schedule requires the billed quantities and associated line charge re in each consumer group or price category code, and the energy delivere

sch ref

8(i): Billed Quantities by Price Component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	WD35	WN35	3.1GEN	3.3GEN	3.4GEN	3.4GEN	6.1	6.2	NDL	NCA Admin G0	NCA Admin G1	NCA Admin G2	NCA Admin G3	CB
			kWh	kWh	kWh	kWh	kWh	kWh	Annual	Annual	kVA=km	New connection application	New connection application	New connection application	New connection application	Annual
0S	Streetlamps	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
0UNM	Unmetered Supplies	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1RL	15 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1RS	15 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1GL	15 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	20 - 150 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2HLFC	or 30 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2LLFC	150kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HLF	150kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.1	3000kVA	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.3	3000kVA	Standard	-	-	-	2,349	-	-	-	-	-	-	-	-	-	-
3.4	3000kVA	Standard	-	-	-	-	16	-	-	-	-	-	-	-	-	-
3.5	3000kVA	Standard	3,326	1,495	-	-	-	16	-	-	-	-	-	-	-	-
6.1	> 3000,	Non-standard	-	-	-	-	-	-	1	-	-	-	-	-	-	-
6.2	> 3000,	Non-standard	-	-	-	-	-	-	-	1	-	-	-	-	-	-
CB	Cobb River Hydro	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MAT	Matiri Hydro	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Connections	-	Standard	-	-	-	-	-	-	-	29,606	-	-	-	-	-	-
Solar Connections	-	Standard	-	-	-	-	-	-	-	-	-	723	48	13	-	-
0	-	[Select one]	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard consumer totals			3,326	1,495	-	2,349	16	16	-	-	29,606	-	723	48	13	-
Non-standard consumer totals			-	-	-	-	-	-	1	1	-	-	-	-	-	-
Total for all consumers			3,326	1,495	-	2,349	16	16	1	1	29,606	-	723	48	13	-

SCHEDULE 8: REPORT ON BILLED QUANTITIE

This schedule requires the billed quantities and associated line charge re in each consumer group or price category code, and the energy delivere

sch ref

8(i): Billed Quantities by Price Component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	MAT	Standard DG Part1A	Standard DG Part1	DG >10kw <100kW	DG >100kw <1000kW
			Annual	Per application	Per application	Per application	Per application
0S	Streetlamps	Standard	-	-	-	-	-
0UNM	Unmetered Supplies	Standard	-	-	-	-	-
1RL	15 kVA Capacity	Standard	-	-	-	-	-
1RS	15 kVA Capacity	Standard	-	-	-	-	-
1GL	15 kVA Capacity	Standard	-	-	-	-	-
2	20 - 150 kVA Capacity	Standard	-	-	-	-	-
2HLFC	or 30 kVA Capacity	Standard	-	-	-	-	-
2LLFC	150kVA Capacity	Standard	-	-	-	-	-
HLF	150kVA Capacity	Standard	-	-	-	-	-
3.1	3000kVA	Standard	-	-	-	-	-
3.3	3000kVA	Standard	-	-	-	-	-
3.4	3000kVA	Standard	-	-	-	-	-
3.5	3000kVA	Standard	-	-	-	-	-
6.1	> 3000,	Non-standard	-	-	-	-	-
6.2	> 3000,	Non-standard	-	-	-	-	-
CB	Cobb River Hydro	Non-standard	-	-	-	-	-
MAT	Matiri Hydro	Non-standard	-	-	-	-	-
Connections	-	Standard	-	-	-	-	-
Solar Connections	-	Standard	-	391	3	27	-
0	-	[Select one]	-	-	-	-	-
Standard consumer totals			-	391	3	27	-
Non-standard consumer totals			-	-	-	-	-
Total for all consumers			-	391	3	27	-

Add extra rows for additional consumer groups or price cate

Company Name **Network Tasman Limited**
 For Year Ended **31 March 2022**
 Network / Sub-Network Name **Network Tasman Limited**

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

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

Line charge revenues (\$000) by price component

Price component	OSTL	OUNM	1RLANY	1RLDAY	1RLNIT	1RLWSR	1RLGEN	1RSANY
Rate (eg, \$ per day, \$ per kWh, etc.)	0.00119	0.533	0.0734	0.0804	0.0129	0.0196	0	0.0245

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)
0S	Streetlamps	Standard	\$181	-
0UNM	Unmetered Supplies	Standard	\$14	-
1RL	15 kVA Capacity	Standard	\$7,281	\$2,754
1RS	15 kVA Capacity	Standard	\$8,886	\$3,832
1GL	15 kVA Capacity	Standard	\$1,840	\$614
2	20 - 150 kVA Capacity	Standard	\$7,590	\$2,611
2HLFC	or 30 kVA Capacity	Standard	\$4	\$0
2LLFC	150kVA Capacity	Standard	\$63	\$12
HLF	150kVA Capacity	Standard	\$528	\$173
3.1	3000kVA	Standard	\$268	\$31
3.3	3000kVA	Standard	\$340	\$77
3.4	3000kVA	Standard	\$6,396	\$1,298
3.5	3000kVA	Standard	\$559	\$91
6.1	> 3000,	Non-standard	\$1,611	\$22
6.2	> 3000,	Non-standard	\$494	\$33
CB	-	Non-standard	\$1,627	-
MAT	MAT, CB, EG etc	Non-standard	\$6	-
Connections	-	Standard	\$430	-
Solar Connections	-	Standard	\$53	-

Total distribution line charge revenue	Total transmission line charge revenue (if available)
\$138	\$43
\$10	\$3
\$4,635	\$2,646
\$5,429	\$3,457
\$1,203	\$637
\$5,490	\$2,100
\$3	\$1
\$52	\$11
\$420	\$108
\$128	\$140
\$219	\$120
\$4,103	\$2,293
\$316	\$243
\$208	\$1,403
\$213	\$280
\$1,417	\$210
\$4	\$2
\$430	-
\$53	-

\$181	-	-	-	-	-	-	-
-	\$14	-	-	-	-	-	-
-	-	\$5,502	\$173	\$27	\$550	-	-
\$1	-	-	-	-	-	-	\$2,625
\$2	-	-	-	-	-	-	-
\$3	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-

Add extra rows for additional consumer groups or price category codes as necessary

Standard consumer totals	\$34,432	\$11,494
Non-standard consumer totals	\$3,738	\$56
Total for all consumers	\$38,170	\$11,550

\$22,631	\$11,801
\$1,842	\$1,895
\$24,474	\$13,696

\$187	\$14	\$5,502	\$173	\$27	\$550	-	\$2,625
-	-	-	-	-	-	-	-
\$187	\$14	\$5,502	\$173	\$27	\$550	-	\$2,625

8(iii): Number of ICPs directly billed

Check **OK**

Number of directly billed ICPs at year end

SCHEDULE 8: REPORT ON BILLED QUANTITIES

This schedule requires the billed quantities and associated line charge revenue in each consumer group or price category code, and the energy delivered

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

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	1RSDAY	1RSNIT	1RSWSR	1RSGEN	1GLANY	1GLDAY	1GLNIT	1GLWSR	1GLGEN	2ANY	2DAY	2NIT	2WSR	2GEN
0.0301			0.0301	0.0053	0.0075	0	0.0245	0.0301	0.0053	0.0075	0	0.0341	0.0391	0.0115	0.0155	0

0S	Streetlamps	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
0UNM	Unmetered Supplies	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1RL	15 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1RS	15 kVA Capacity	Standard	\$79	\$16	\$260	-	-	-	-	-	-	-	-	-	-	-
1GL	15 kVA Capacity	Standard	-	-	-	-	\$454	\$25	\$2	\$12	-	-	-	-	-	-
2	20 - 150 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	\$2,331	\$730	\$90	\$51	-
2HLFC	or 30 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2LLFC	150kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HLF	150kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.1	3000kVA	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.3	3000kVA	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.4	3000kVA	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.5	3000kVA	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6.1	> 3000,	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6.2	> 3000,	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CB	-	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MAT	MAT, CB, EG etc	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Connections	-	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar Connections	-	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Add extra rows for additional consumer groups or price categories

Standard consumer totals	\$79	\$16	\$260	-	\$454	\$25	\$2	\$12	-	\$2,331	\$730	\$90	\$51	-	-	-
Non-standard consumer totals	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total for all consumers	\$79	\$16	\$260	-	\$454	\$25	\$2	\$12	-	\$2,331	\$730	\$90	\$51	-	-	-

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end

SCHEDULE 8: REPORT ON BILLED QUANTITIES

This schedule requires the billed quantities and associated line charge revenue in each consumer group or price category code, and the energy delivered

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

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	2LANY	2LDAY	2LNIT	2LWSR	2LGEN	2HANY	2HDAY	2HNIT	2HWSR	2HGEN	HLFANY	HLFDAY	HLFNIT	HLFWSR
			0.1316	0.1498	0.0507	0.0572	0	0.262	0.2844	0.1428	0.1701	0	0.0079	0.009	0.0019	0.0017

0S	Streetlamps	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
0UNM	Unmetered Supplies	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1RL	15 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1RS	15 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1GL	15 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	20 - 150 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2HLFC	or 30 kVA Capacity	Standard	-	-	-	-	-	\$3	-	-	\$1	-	-	-	-	-
2LLFC	150kVA Capacity	Standard	\$45	\$5	\$1	\$3	-	-	-	-	-	-	-	-	-	-
HLF	150kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	\$36	\$31	\$3	-
3.1	3000kVA	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.3	3000kVA	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.4	3000kVA	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.5	3000kVA	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6.1	> 3000,	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6.2	> 3000,	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CB	-	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MAT	MAT, CB, EG etc	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Connections	-	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar Connections	-	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Add extra rows for additional consumer groups or price categories

Standard consumer totals	\$45	\$5	\$1	\$3	-	\$3	-	-	\$1	-	\$36	\$31	\$3	-
Non-standard consumer totals	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total for all consumers	\$45	\$5	\$1	\$3	-	\$3	-	-	\$1	-	\$36	\$31	\$3	-

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end

SCHEDULE 8: REPORT ON BILLED QUANTITIES

This schedule requires the billed quantities and associated line charge revenue in each consumer group or price category code, and the energy delivered

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

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	HLFGEN	1RL	1RS	1GL	2	2HLFC	2LLFC	HLF	AnyDem31	AnyDem33	AnyDem34	AnyDem35	WinDem	kVAr
0			0	0.15	1.00	1.00	0.09	0.15	0.15	0.4032	0.1276	0.1462	0.154	0.1462	0.281	0.2899

0S	Streetlamps	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
0UNM	Unmetered Supplies	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1RL	15 kVA Capacity	Standard	-	\$1,029	-	-	-	-	-	-	-	-	-	-	-	-
1RS	15 kVA Capacity	Standard	-	-	\$5,905	-	-	-	-	-	-	-	-	-	-	-
1GL	15 kVA Capacity	Standard	-	-	-	\$1,344	-	-	-	-	-	-	-	-	-	-
2	20 - 150 kVA Capacity	Standard	-	-	-	-	\$4,385	-	-	-	-	-	-	-	-	-
2HLFC	or 30 kVA Capacity	Standard	-	-	-	-	-	\$0	-	-	-	-	-	-	-	-
2LLFC	150kVA Capacity	Standard	-	-	-	-	-	-	\$9	-	-	-	-	-	-	-
HLF	150kVA Capacity	Standard	-	-	-	-	-	-	-	\$458	-	-	-	-	-	-
3.1	3000kVA	Standard	-	-	-	-	-	-	-	-	\$102	-	-	-	\$133	-
3.3	3000kVA	Standard	-	-	-	-	-	-	-	-	-	\$125	-	-	\$109	-
3.4	3000kVA	Standard	-	-	-	-	-	-	-	-	-	-	\$2,693	-	\$2,037	\$14
3.5	3000kVA	Standard	-	-	-	-	-	-	-	-	-	-	-	\$223	\$226	-
6.1	> 3000,	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6.2	> 3000,	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CB	-	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MAT	MAT, CB, EG etc	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Connections	-	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar Connections	-	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Add extra rows for additional consumer groups or price categories

Standard consumer totals	-	\$1,029	\$5,905	\$1,344	\$4,385	\$0	\$9	\$458	\$102	\$125	\$2,693	\$223	\$2,505	\$14
Non-standard consumer totals	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total for all consumers	-	\$1,029	\$5,905	\$1,344	\$4,385	\$0	\$9	\$458	\$102	\$125	\$2,693	\$223	\$2,505	\$14

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end

SCHEDULE 8: REPORT ON BILLED QUANTITIES

This schedule requires the billed quantities and associated line charge revenue in each consumer group or price category code, and the energy delivered

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

			SD31	SN31	WD31	WN31	SD33	SN33	WD33	WN33	SD34	SN34	WD34	WN34	SD35	SN35
Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	0.0031	0.0015	0.0056	0.0015	0.0094	0.0051	0.0242	0.0051	0.0094	0.0051	0.0242	0.0051	0.0064	0.0039
0S	Streetlamps	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
0UNM	Unmetered Supplies	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1RL	15 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1RS	15 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1GL	15 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	20 - 150 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2HLFC	or 30 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2LLFC	150kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HLF	150kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.1	3000kVA	Standard	\$12	\$2	\$16	\$2	-	-	-	-	-	-	-	-	-	-
3.3	3000kVA	Standard	-	-	-	-	\$37	\$9	\$55	\$5	-	-	-	-	-	-
3.4	3000kVA	Standard	-	-	-	-	-	-	-	-	\$495	\$97	\$983	\$77	-	-
3.5	3000kVA	Standard	-	-	-	-	-	-	-	-	-	-	-	-	\$27	\$7
6.1	> 3000,	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6.2	> 3000,	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CB	-	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MAT	MAT, CB, EG etc	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Connections	-	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar Connections	-	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<i>Add extra rows for additional consumer groups or price categories</i>																
Standard consumer totals			\$12	\$2	\$16	\$2	\$37	\$9	\$55	\$5	\$495	\$97	\$983	\$77	\$27	\$7
Non-standard consumer totals			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total for all consumers			\$12	\$2	\$16	\$2	\$37	\$9	\$55	\$5	\$495	\$97	\$983	\$77	\$27	\$7

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end

SCHEDULE 8: REPORT ON BILLED QUANTITIE

This schedule requires the billed quantities and associated line charge re in each consumer group or price category code, and the energy delivere

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

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	WD35	WN35	3.1GEN	3.3GEN	3.4GEN	3.4GEN	6.1	6.2	NDL	NCA Admin G0	NCA Admin G1	NCA Admin G2	NCA Admin G3	CB	
			0.0206	0.0039	0.00	0.00	0.00	0.00	Annual	Annual	7.714143	125	250	325	400	Annual	
0S	Streetlamps	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
0UNM	Unmetered Supplies	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1RL	15 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1RS	15 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1GL	15 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	20 - 150 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2HLFC	or 30 kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2LLFC	150kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HLF	150kVA Capacity	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.1	3000kVA	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.3	3000kVA	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.4	3000kVA	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.5	3000kVA	Standard	\$69	\$6	-	-	-	-	-	-	-	-	-	-	-	-	-
6.1	> 3000,	Non-standard	-	-	-	-	-	-	\$1,611	-	-	-	-	-	-	-	-
6.2	> 3000,	Non-standard	-	-	-	-	-	-	-	\$494	-	-	-	-	-	-	-
CB	-	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-	\$1,627
MAT	MAT, CB, EG etc	Non-standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Connections	-	Standard	-	-	-	-	-	-	-	-	\$228	-	\$181	\$16	\$5	-	-
Solar Connections	-	Standard	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<i>Add extra rows for additional consumer groups or price category</i>																	
Standard consumer totals			\$69	\$6	-	-	-	-	-	-	\$228	-	\$181	\$16	\$5	-	-
Non-standard consumer totals			-	-	-	-	-	-	\$1,611	\$494	-	-	-	-	-	-	\$1,627
Total for all consumers			\$69	\$6	-	-	-	-	\$1,611	\$494	\$228	-	\$181	\$16	\$5	\$1,627	

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end

SCHEDULE 8: REPORT ON BILLED QUANTITIES

This schedule requires the billed quantities and associated line charge revenue in each consumer group or price category code, and the energy delivered

39 8(ii): Line Charge Revenues (\$000) by Price Code

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	MAT	Standard DG Part1A	Standard DG Part1	DG >10kw <100kW	DG >100kw <1000kW
Consumer group name or price category code	Annual	100	200	500	1000

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	MAT	Standard DG Part1A	Standard DG Part1	DG >10kw <100kW	DG >100kw <1000kW
0S	Streetlamps	Standard	-	-	-	-	-
0UNM	Unmetered Supplies	Standard	-	-	-	-	-
1RL	15 kVA Capacity	Standard	-	-	-	-	-
1RS	15 kVA Capacity	Standard	-	-	-	-	-
1GL	15 kVA Capacity	Standard	-	-	-	-	-
2	20 - 150 kVA Capacity	Standard	-	-	-	-	-
2HLFC	or 30 kVA Capacity	Standard	-	-	-	-	-
2LLFC	150kVA Capacity	Standard	-	-	-	-	-
HLF	150kVA Capacity	Standard	-	-	-	-	-
3.1	3000kVA	Standard	-	-	-	-	-
3.3	3000kVA	Standard	-	-	-	-	-
3.4	3000kVA	Standard	-	-	-	-	-
3.5	3000kVA	Standard	-	-	-	-	-
6.1	> 3000,	Non-standard	-	-	-	-	-
6.2	> 3000,	Non-standard	-	-	-	-	-
CB	-	Non-standard	-	-	-	-	-
MAT	MAT, CB, EG etc	Non-standard	\$6	-	-	-	-
Connections	-	Standard	-	-	-	-	-
Solar Connections	-	Standard	-	\$39	\$1	\$14	-

Add extra rows for additional consumer groups or price categories

Standard consumer totals	-	\$39	\$1	\$14	-
Non-standard consumer totals	\$6	-	-	-	-
Total for all consumers	\$6	\$39	\$1	\$14	-

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end

Company Name	Network Tasman Limited
For Year Ended	31 March 2022
Network / Sub-network Name	Network Tasman Limited

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

sch ref	Voltage	Asset category	Asset class	Units	Items at start of	Items at end of	Data accuracy	
					year (quantity)	year (quantity)	Net change	(1-4)
8	All	Overhead Line	Concrete poles / steel structure	No.	26,579	26,321	(258)	3
9	All	Overhead Line	Wood poles	No.	1,692	1,684	(8)	3
10	All	Overhead Line	Other pole types	No.	437	418	(19)	3
11	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	281	281	-	4
12	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	4
13	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	34	34	-	4
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	3	3	-	4
17	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	4
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	4
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	4
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	4
21	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	4
22	HV	Zone substation Buildings	Zone substations up to 66kV	No.	15	15	-	4
23	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	4
24	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	4
25	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	9	9	-	4
26	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	4
27	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	104	109	5	4
28	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	4
29	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	9	15	6	4
30	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	22	22	-	4
31	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	95	104	9	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	8	8	-	4
33	HV	Zone Substation Transformer	Zone Substation Transformers	No.	25	27	2	4
34	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1,889	1,887	(2)	3
35	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	3
36	HV	Distribution Line	SWER conductor	km	-	-	-	4
37	HV	Distribution Cable	Distribution UG XLPE or PVC	km	147	150	3	3
38	HV	Distribution Cable	Distribution UG PILC	km	135	135	-	3
39	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	4
40	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	73	71	(2)	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	-	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1,323	1,348	25	3
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	202	154	(48)	3
44	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	140	147	7	3
45	HV	Distribution Transformer	Pole Mounted Transformer	No.	3,822	3,829	7	3
46	HV	Distribution Transformer	Ground Mounted Transformer	No.	789	825	36	3
47	HV	Distribution Transformer	Voltage regulators	No.	11	9	(2)	4
48	HV	Distribution Substations	Ground Mounted Substation Housing	No.	25	25	-	4
49	LV	LV Line	LV OH Conductor	km	492	490	(2)	3
50	LV	LV Cable	LV UG Cable	km	681	694	13	3
51	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	-	-	-	4
52	LV	Connections	OH/UG consumer service connections	No.	41,735	42,378	643	4
53	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	113	123	10	4
54	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	1	1	-	4
55	All	Capacitor Banks	Capacitors including controls	No.	10	9	(1)	4
56	All	Load Control	Centralised plant	Lot	5	5	-	4
57	All	Load Control	Relays	No.	-	-	-	4
58	All	Civils	Cable Tunnels	km	-	-	-	4

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			Number of assets at disclosure year end by installation date																				
8	Disclosure Year (year ended)		31 March 2022																				
9	Voltage	Asset category	Asset class	Units	pre-1940	1940	1950	1960	1970	1980	1990	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
10	All	Overhead Line	Concrete poles / steel structure	No.	2,141	1,250	6,859	6,065	1,957	3,540	993	63	180	124	169	162	91	167	170	155	132	189	134
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
12	All	Overhead Line	Other pole types	No.	--	--	37	129	47	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	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	--	--	--	--
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	3	5	5	1	--	--	--	2	--	2	--	2	--	1	--	--
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	39	83	461	516	154	274	103	7	7	7	12	12	6	10	3	8	13	34	16
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	
40	HV	Distribution Cable	Distribution UG PILC	km	--	--	--	3	23	40	23	2	2	2	12	6	2	4	3	3	2	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 sectionaliser:	No.	--	--	--	--	--	--	--	2	--	--	1	2	2	2	--	--	--	4	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	
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	
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.	--	14	128	495	469	853	589	36	77	81	64	74	45	38	22	42	45	44	34
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	--	--	--	7	82	63	75	14	20	31	30	33	27	42	25	31	24	19	16
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	--	21	143	118	41	58	12	76	1	1	1	2	2	3	1	1	2	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
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
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	--	--	--	3	2	5	21	--	10	--	10	--	12	14	--	1	1	--	11
56	All	SCADA and communications	SCADA and communications equipment operating as a single sys	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	Network Tasman Limited
For Year Ended	31 March 2022
Network / Sub-network Name	Network Tasman Limited

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 c

sch ref

8	Disclosure Year (year ended)		2012 to 2021													No. with age unknown	Items at end of year	No. with default dates	Data accuracy (1-4)		
	31 March 2022		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021									
9	Voltage	Asset category	Asset class	Units																	
10	All	Overhead Line	Concrete poles / steel structure	No.	137	128	150	203	33	130	70	100	155	117	466	26,321	-	1			
11	All	Overhead Line	Wood poles	No.	15	14	29	-	-	8	42	84	93	4	255	1,684	-	1			
12	All	Overhead Line	Other pole types	No.	-	1	-	-	-	-	-	-	-	-	51	418	-	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	-	-	34	-	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	-	-	-	-	-	-	15	-	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	-	-	-	-	-	-	9	-	4			
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	4			
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	-	-	-	1	-	-	-	2	35	109	-	1			
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	4			
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	-	-	-	-	-	-	-	15	-	4			
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	-	-	-	-	-	-	-	-	2	-	22	-	3			
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	8	-	-	12	-	-	-	-	-	-	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	-	-	-	-	-	-	27	-	4			
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	12	16	6	2	-	6	8	21	21	20	-	1,887	-	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	3	5	3	3	-	5	9	8	8	9	-	150	-	2			
40	HV	Distribution Cable	Distribution UG PILC	km	1	2	1	2	-	-	-	-	-	-	-	135	-	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 sectionaliser:	No.	8	4	6	4	5	6	1	8	8	-	-	71	-	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.	19	10	13	25	5	7	13	34	18	10	849	1,348	-	2			
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	4	4	8	9	-	5	2	5	5	-	9	154	-	2			
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	-	2	-	-	4	6	15	10	11	69	147	-	2			
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	46	80	61	27	44	61	36	82	85	11	75	3,829	-	2			
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	4	19	31	22	28	22	40	38	24	16	-	825	-	2			
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	-	-	1	-	-	-	-	2	490	-	2			
52	LV	LV Cable	LV UG Cable	km	9	9	11	12	3	14	13	17	16	19	13	694	-	2			
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	-	-	-	-	-	-	-	-	-	-	-	-	-	2			
54	LV	Connections	OH/UG consumer service connections	No.	464	460	557	442	447	538	562	529	622	723	29,246	42,378	-	2			
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	6	-	-	14	-	-	-	3	-	-	123	-	3			
56	All	SCADA and communications	SCADA and communications equipment operating as a single sys	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 2022**

Network / Sub-network Name **Network Tasman Limited**

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref

9				
10	Circuit length by operating voltage (at year end)	Overhead (km)	Underground (km)	Total circuit length (km)
11	> 66kV	-	-	-
12	50kV & 66kV	158	-	158
13	33kV	123	37	160
14	SWER (all SWER voltages)	-	-	-
15	22kV (other than SWER)	19	13	31
16	6.6kV to 11kV (inclusive—other than SWER)	1,868	286	2,154
17	Low voltage (< 1kV)	490	694	1,184
18	Total circuit length (for supply)	2,658	1,030	3,688
19				
20	Dedicated street lighting circuit length (km)	-	-	-
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			18
22				
23	Overhead circuit length by terrain (at year end)	(% of total overhead length)		
24	Urban	177		7%
25	Rural	2,285		86%
26	Remote only	70		3%
27	Rugged only	118		4%
28	Remote and rugged	8		0%
29	Unallocated overhead lines	-		-
30	Total overhead length	2,658		100%
31				
32		(% of total circuit length)		
33	Length of circuit within 10km of coastline or geothermal areas (where known)	1,671		45%
34		(% of total overhead length)		
35	Overhead circuit requiring vegetation management	2,658		100%

Company Name **Network Tasman Limited**
 For Year Ended **31 March 2022**

SCHEDULE 9d: REPORT ON EMBEDDED NETWORKS

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

sch ref

	Location *	Number of ICPs served	Line charge revenue (\$000)
8			
9	n/a		
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			

* 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 2022**

Network / Sub-network Name **Network Tasman Limited**

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref

9e(i): Consumer Connections

Number of ICPs connected in year by consumer type

Consumer types defined by EDB*

Consumers 20kVA and less
Consumers greater than 20kVA
0
0
0

* include additional rows if needed

Number of connections (ICPs)

687
37
-
-
-

Connections total

724

Distributed generation

Number of connections made in year

294

connections

Capacity of distributed generation installed in year

2.28

MVA

9e(ii): System Demand

Maximum coincident system demand

GXP demand

115

plus Distributed generation output at HV and above

34

Maximum coincident system demand

149

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

19

Demand on system for supply to consumers' connection points

130

Demand at time of maximum coincident demand (MW)

Electricity volumes carried

Electricity supplied from GXPs

633

less Electricity exports to GXPs

101

plus Electricity supplied from distributed generation

251

less Net electricity supplied to (from) other EDBs

92

Electricity entering system for supply to consumers' connection points

691

less Total energy delivered to ICPs

652

Electricity losses (loss ratio)

39

5.6%

Load factor

0.61

9e(iii): Transformer Capacity

Distribution transformer capacity (EDB owned)

461

Distribution transformer capacity (Non-EDB owned, estimated)

44

Total distribution transformer capacity

505

Zone substation transformer capacity

396

(MVA)

Company Name	Network Tasman Limited
For Year Ended	31 March 2022
Network / Sub-network Name	Network Tasman Limited

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

8 **10(i): Interruptions**

9 **Interruptions by class**

	Number of interruptions
10 Class A (planned interruptions by Transpower)	1
11 Class B (planned interruptions on the network)	171
12 Class C (unplanned interruptions on the network)	146
13 Class D (unplanned interruptions by Transpower)	3
14 Class E (unplanned interruptions of EDB owned generation)	-
15 Class F (unplanned interruptions of generation owned by others)	-
16 Class G (unplanned interruptions caused by another disclosing entity)	-
17 Class H (planned interruptions caused by another disclosing entity)	-
18 Class I (interruptions caused by parties not included above)	-
19 Total	321

21 **Interruption restoration**

	≤3Hrs	>3hrs
22 Class C interruptions restored within	94	52

24 **SAIFI and SAIDI by class**

	SAIFI	SAIDI
25 Class A (planned interruptions by Transpower)	0.01	4.4
26 Class B (planned interruptions on the network)	0.21	66.1
27 Class C (unplanned interruptions on the network)	1.11	110.1
28 Class D (unplanned interruptions by Transpower)	0.08	22.0
29 Class E (unplanned interruptions of EDB owned generation)	-	-
30 Class F (unplanned interruptions of generation owned by others)	-	-
31 Class G (unplanned interruptions caused by another disclosing entity)	-	-
32 Class H (planned interruptions caused by another disclosing entity)	-	-
33 Class I (interruptions caused by parties not included above)	-	-
34 Total	1.40	202.6

36 **Normalised SAIFI and SAIDI**

	Normalised SAIFI	Normalised SAIDI
37 Classes B & C (interruptions on the network)	1.31	176.2

Company Name	Network Tasman Limited
For Year Ended	31 March 2022
Network / Sub-network Name	Network Tasman Limited

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

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

Cause	SAIFI	SAIDI
Lightning	0.15	12.9
Vegetation	0.02	1.5
Adverse weather	0.08	10.7
Adverse environment	0.01	1.7
Third party interference	0.18	17.4
Wildlife	0.11	6.4
Human error	-	-
Defective equipment	0.37	39.0
Cause unknown	0.19	20.5

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	-	-
Subtransmission cables	-	-
Subtransmission other	-	-
Distribution lines (excluding LV)	0.20	63.5
Distribution cables (excluding LV)	0.00	0.5
Distribution other (excluding LV)	0.01	2.1

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.41	31.7
Subtransmission cables	-	-
Subtransmission other	-	-
Distribution lines (excluding LV)	0.61	68.2
Distribution cables (excluding LV)	0.07	9.0
Distribution other (excluding LV)	0.01	1.2

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	7	281	2.49
Subtransmission cables	-	37	-
Subtransmission other	-	-	-
Distribution lines (excluding LV)	125	1,887	6.62
Distribution cables (excluding LV)	7	286	2.45
Distribution other (excluding LV)	7	-	-
Total	146		

Company Name	<u>Network Tasman Limited</u>
For Year Ended	<u>31 March 2022</u>

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 relatively low return on investment. This is because posted discounts reduce NTL’s regulated prices/revenues and therefore return on investment.

However, for 2021/22 Network Tasman’s return on investment is relatively high when compared to the benchmarks used in the ID regime. Historically high revaluations are the primary driver of this. For 2021/22 revaluations were \$12.2m compared to a 4-year average of \$2.8m.

There have been no changes in classification.

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.

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 been the following changes in classification.

<i>Category 2021</i>	<i>Category 2022</i>	<i>\$000</i>	<i>Explanation</i>
Distribution Substations & Transformers	Other Network Assets	44	Fuse classification correction
Other Network Assets	Distribution & LV Cable	91	Easements reclassified as cable
Other Network Assets	Distribution Substations & Transformers	61	Transformer components reclassified
Other Network Assets	Subtransmission cable	55	Easements reclassified as cable
Other small recategorisation		87	

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 \$303,000 @28% = \$84,800,

less movement in provisions temporary difference \$45,000 @28% = \$12,600.

Making temporary differences of \$72,200.

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 \$873,000.

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 reduced the regulatory asset base by \$93,000 in the current year.

There are no asset reclassification identified in box 4 so there is no impact on the asset allocations.

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 \$400,000 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.

No items have been reclassified.

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 over target by \$123,000 due to higher than anticipated increased industrial load which needed new transformers.
- Asset relocations are \$459,000 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 are basically on target.
- Reliability, safety and environment – quality of supply is under target by \$2.2million. This is due to the Founders to Wakapuaka 33kV Cable project being delayed until the following financial year.
- Reliability, safety and environment – legislative and regulatory is \$700,000 under target. This \$700,000 should have been budgeted as reliability, safety and environment – other.
- Reliability, safety and environment – Other reliability, safety and environment is close to target.
- System Growth is \$2,1million (42%) under target which primarily relates to the Motueka Zone Substation Upgrade which is underway, but behind schedule.
- Non-network assets expenditure is \$413,000 under target with less software expenditure than expected, and the delayed arrival of some hardware.

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

- Service interruptions and emergencies costs are 13% (\$145,000) over target due to 2 storms and some cable faults incurring costs that were not expected.
- Vegetation management costs is only slightly under target - 3% (\$42,000).
- Routine and corrective maintenance and inspection costs and asset replacement and renewal expenditure are both below target as maintenance work was impacted by the COVID 19 lockdowns.
- Non-network expenditure is 1% (\$33,000) below target. This variance is spread over many expenses, none that are significant.

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 2021/22 regulatory year, Network Tasman forecast line charge revenues of \$37.4m and recovered actual revenues of \$38.2m, a difference of approximately \$800,000 or 2%.

Higher than forecast consumption from Group 1 (15kVA) connections was the primary driver behind Network Tasman recovering higher than forecast line charge revenue. As Group 1 largely consists of residential connections, higher than forecast volumes for Group 1 is attributed to higher residential consumption during COVID19 lockdowns and more people working from home across the year.

The methodology in determining prices was unchanged from previous years.

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

Planned SAIDI was over target for the 2021/22 year (110/75). A lightning storm in Marsden Valley on 5 August 2021 resulted in a loss of supply to Richmond, Brightwater and Wakefield consumers and accumulated 12.8 SAIDI points. Another unplanned outage occurred on 20 Feb 2022 and in the same area, resulting from earlier damage to lightning protection equipment in Marsden Valley, caused 9.7 SAIDI points.

There was also a major storm event on July 17 2021 which resulted in 9.6 SAIDI points. A number of outages exceeding 3 hours in duration resulted from this event.

Planned SAIDI was under target for the 2021/22 year (66/100). Maintenance works were disrupted by Covid-19 lockdowns during the year. The disruption has not impacted the overall reliability of the network however and it is expected that the planned works will be caught up during 2022/23.

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 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.

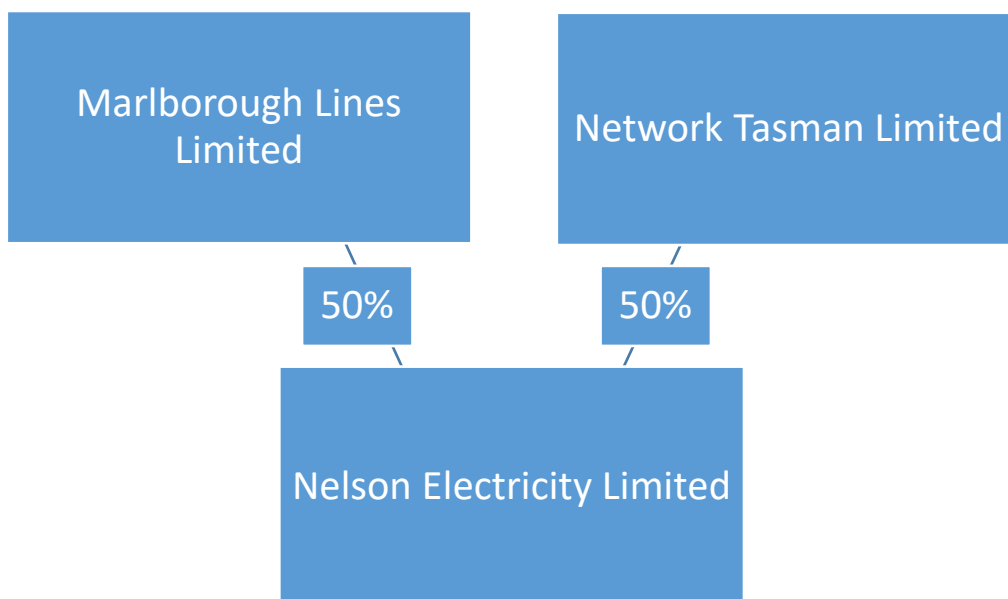
Box 15: Disclosure of amendment to previously disclosed information

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	13
Other sundry	4
Total Annual Charge	<u>31</u>

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 rate of the Electricity Authority levies are published in the New Zealand Gazette.

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 system demand” (row 28) instead of “Demand on system for supply to consumers' connection points” (row 30) 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 31kW/km.

Demand density	31
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10: Report on Network Reliability– The SAIFI calculation has been prepared on a basis consistent with the previous year’s disclosure.

Network Tasman Limited counts SAIFI as follows:

The number of ICPs that experience an interruption when a fault occurs is recorded once and contributes to the SAIFI for that fault. In a few cases, there may be partial restoration of supply to a subset of the affected ICPs, followed by a loss of supply to those same ICPs as the fault finding process takes place. In such a case, the additional ‘on/off’ of the affected ICPs within the outage event does not contribute to the SAIFI count for the outage.

Once all affected ICPs have been restored, any subsequent interruption is recorded as a separate interruption for SAIFI purposes - for example due to further repair work relating to an earlier outage.

SAIFI was within the bounds of expected performance.

Certification for Year-end Disclosures

Clause 2.9.2

We, Michael John MCCLISKIE 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.



Michael John MCCLISKIE



Anthony Page REILLY

29 July 2022

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 2022 as required by the electricity distribution information disclosure determination 2012

The Network Tasman Limited (the Company) is required to disclose certain information under the Electricity Distribution Information Disclosure Determination 2012 (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 2022 (the Disclosure Information) complies, in all material respects, with the Determination.

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

- Schedules 1 to 4, 5a to 5g, 6a and 6b, 7, 10 and 14 (limited to the explanatory notes in boxes 1 to 11) of the Determination.
- Clause 2.3.6 of the Determination and clauses 2.2.11(1)(g) and 2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012 (the IM Determination), in respect of the basis for valuation of related party transactions (the Related Party Transaction Information).

This assurance report should be read in conjunction with the Commerce Commission's Information Disclosure exemption, issued to all electricity distribution businesses on 17 May 2021 under clause 2.11 of the Determination. The Commerce Commission granted an exemption from the requirement that the assurance report, in respect of the information in Schedule 10 of the ID Determination, must take into account any issues arising out of the Company's recording of SAIDI, SAIFI, and number of interruptions due to successive interruptions.

Opinion

In our opinion, in all material respects:

- as far as appears from an examination, proper records to enable the complete and accurate compilation of the Disclosure Information have been kept by the Company;
- as far as appears from an examination, the information used in the preparation of the Disclosure Information has been properly extracted from the Company's accounting and other records, sourced from the Company's financial and non-financial systems;

- the Disclosure Information complies, in all material respects, with the Determination; and
- the basis for valuation of related party transactions complies with the Determination and the IM Determination.

Basis for opinion

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

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

Key assurance matters

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

Key assurance matter	How our procedures addressed the key assurance matter
<p>Cost allocation</p> <p>The Determination and the IM Determination place a requirement on the Company to allocate indirect costs between its regulated and non-regulated business.</p> <p>The Company has a significant investment property portfolio, a fibre network, and a smart meter network that are not part of the regulated business.</p> <p>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.</p> <p>The IM Determination sets out the rules and processes for allocating non-directly attributable costs.</p>	<p>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.</p> <p>The procedures we carried out, to satisfy ourselves that indirect costs were correctly allocated, included:</p> <ul style="list-style-type: none"> • reconciling the regulated and unregulated financial information to the audited financial statements for the year ended 31 March 2022, 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;

Key assurance matter	How our procedures addressed the key assurance matter
	<ul style="list-style-type: none"> • 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 • testing a sample of cost allocation calculations.
<p><i>Accuracy of the number and duration of electricity outages</i></p> <p>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.</p> <p>This is a key audit 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.</p> <p>There can also be significant consequences if the Company breaches the reliability thresholds.</p> <p>The Commerce Commission has issued an Exemption notice which excludes the assurance report from coverage of the information, in Schedule 10 of the Determination, for any issues arising out of the Company’s recording of SAIDI, SAIFI and number of interruptions due to successive interruptions. We need to ensure that the Company meets the criteria for the Exemption to apply, including that it makes the necessary disclosures so the exclusion to the assurance opinion applies.</p>	<p>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.</p> <p>Our procedures to assess the adequacy of the Company’s methods to identify and record electricity outages and their duration included:</p> <ul style="list-style-type: none"> • 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; • checked the SAIDI and SAIFI ratios were correctly calculated in accordance with the Determination and the IM Determination; • obtained explanations for all significant variances to forecast; and • testing the accuracy of the number of connections to the Electricity Authority’s register. <p>With respect to the Exemption, we:</p> <ul style="list-style-type: none"> • obtained and documented our understanding of the Company’s methods by which electricity outages and their duration are recorded where an outage event results in successive interruptions of supply; • compared this to the documented process that the Company followed in the previous year; and • identified potential incidences of successive interruptions of supply to help provide assurance

Key assurance matter	How our procedures addressed the key assurance matter
	<p>that the Company's methods, by which electricity outages and their duration are recorded where an outage event results in successive interruptions of supply, were the same for both years.</p> <p>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.</p>
<p><i>Valuation of related-party transactions at arm's-length</i></p> <p>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.</p> <p>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.</p> <p>This a key audit 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.</p>	<p>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.</p> <p>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:</p> <ul style="list-style-type: none"> • 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 • confirming the material accuracy of related party values disclosed, and compliance of their calculation with the Determination and the IM Determination.

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.
- The Company's basis for valuation of related party transactions in the disclosure year has complied, in all material respects, with clause 2.3.6 of the Determination and clauses 2.2.11(1)(g) and 2.2.11(5) of the IM Determination.

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

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

Inherent limitations

Because of the inherent limitations of an assurance engagement, together with the internal control structure, it is possible that fraud, error, or non-compliance with the Determination may occur and not be detected. A reasonable assurance engagement throughout the disclosure year does not provide assurance on whether compliance with the Determination will continue in the future.

Restricted use

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

Independence and quality control

We complied with the Auditor-General's:

- independence and other ethical requirements, which incorporate the independence and ethical requirements of Professional and Ethical Standard 1 issued by the New Zealand Auditing and Assurance Standards Board; and
- quality control requirements, which incorporate the quality control requirements of Professional and Ethical Standard 3 (Amended) issued by the New Zealand Auditing and Assurance Standards Board.

The Auditor-General, and his employees, and Audit New Zealand and its employees may deal with the Company and its subsidiaries 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 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 and its subsidiaries.



John Mackey
Audit New Zealand
On behalf of the Auditor-General
Christchurch, New Zealand
29 July 2022