COMMERCE COMMISSION
NEW ZEALAND

EDB Information Disclosure Requirements
Information Templates
for
Schedules 1–10

Company Name	Network Tasman Limited
Disclosure Date	31 August 2021
Disclosure Year (year ended)	31 March 2021

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

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2021**

SCHEDULE 1: ANALYTICAL RATIOS

This schedule calculates expenditure, revenue and service ratios from the information disclosed. The disclosed ratios may vary for reasons that are company specific and, as a result, must be interpreted with care. The Commerce Commission will publish a summary and analysis of information disclosed in accordance with the ID determination. This will include information disclosed in accordance with this and other schedules, and information disclosed under the other requirements of the determination.
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

7 1(i): Expenditure metrics

sch ref		Expenditure per GWh energy delivered to ICPs ($/GWh)	Expenditure per average no. of ICPs ($/ICP)	Expenditure per MW maximum coincident system demand ($/MW)	Expenditure per km circuit length ($/km)	Expenditure per MVA of capacity from EDB-owned distribution transformers ($/MVA)
8						
9	**Operational expenditure**	18,224	282	100,565	3,118	25,658
10	Network	10,176	158	56,156	1,741	14,328
11	Non-network	8,047	125	44,409	1,377	11,331
12						
13	**Expenditure on assets**	15,269	236	84,261	2,612	21,499
14	Network	14,563	225	80,362	2,492	20,504
15	Non-network	706	11	3,898	121	995
16						

17 1(ii): Revenue metrics

sch ref		Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
18			
19	**Total consumer line charge revenue**	56,925	881
20	Standard consumer line charge revenue	61,133	792
21	Non-standard consumer line charge revenue	35,282	902,550
22			

23 1(iii): Service intensity measures

sch ref			
24			
25	Demand density	35	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
26	Volume density	171	*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	15,482	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*
29			

30 1(iv): Composition of regulatory income

sch ref		($000)	% of revenue
31			
32	Operational expenditure	11,454	32.11%
33	Pass-through and recoverable costs excluding financial incentives and wash-ups	12,472	34.96%
34	Total depreciation	6,984	19.58%
35	Total revaluations	2,650	7.43%
36	Regulatory tax allowance	1,939	5.44%
37	Regulatory profit/(loss) including financial incentives and wash-ups	5,477	15.35%
38	**Total regulatory income**	35,677	
39			

40 1(v): Reliability

sch ref			
41			
42	Interruption rate	7.51	*Interruptions per 100 circuit km*

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SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

This schedule requires information on the Return on Investment (ROI) for the EDB relative to the Commerce Commission's estimates of post tax WACC and vanilla WACC. EDBs must calculate their ROI based on a monthly basis if required by clause 2.3.3 of the ID Determination or if they elect to. If an EDB makes this election, information supporting this calculation must be provided in 2(iii).
EDBs must provide explanatory comment on their ROI in Schedule 14 (Mandatory Explanatory Notes).
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref				
7	**2(i): Return on Investment**	**CY-2**	**CY-1**	**Current Year CY**
8		**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
9	**ROI – comparable to a post tax WACC**	**%**	**%**	**%**
10	Reflecting all revenue earned	3.35%	3.91%	2.82%
11	Excluding revenue earned from financial incentives	1.42%	2.21%	2.82%
12	Excluding revenue earned from financial incentives and wash-ups	1.55%	2.34%	2.82%
14	**Mid-point estimate of post tax WACC**	4.75%	4.27%	3.72%
15	25th percentile estimate	4.07%	3.59%	3.04%
16	75th percentile estimate	5.43%	4.95%	4.40%
19	**ROI – comparable to a vanilla WACC**			
20	Reflecting all revenue earned	3.86%	4.33%	3.16%
21	Excluding revenue earned from financial incentives	1.93%	2.63%	3.16%
22	Excluding revenue earned from financial incentives and wash-ups	2.06%	2.77%	3.16%
24	**WACC rate used to set regulatory price path**	7.19%	7.19%	4.57%
26	**Mid-point estimate of vanilla WACC**	5.26%	4.69%	4.05%
27	25th percentile estimate	4.58%	4.01%	3.37%
28	75th percentile estimate	5.94%	5.37%	4.73%

sch ref				
30	**2(ii): Information Supporting the ROI**		**($000)**	
32	Total opening RAB value	174,395		
33	*plus* Opening deferred tax	(2,474)		
34	**Opening RIV**		171,921	
36	**Line charge revenue**		35,779	
38	Expenses cash outflow	23,926		
39	*add* Assets commissioned	8,066		
40	*less* Asset disposals	847		
41	*add* Tax payments	1,201		
42	*less* Other regulated income	(102)		
43	**Mid-year net cash outflows**		32,448	
45	**Term credit spread differential allowance**		–	
47	Total closing RAB value	177,306		
48	*less* Adjustment resulting from asset allocation	26		
49	*less* Lost and found assets adjustment	–		
50	*plus* Closing deferred tax	(3,213)		
51	**Closing RIV**		174,068	
53	**ROI – comparable to a vanilla WACC**			3.16%
55	Leverage (%)			42%
56	Cost of debt assumption (%)			2.82%
57	Corporate tax rate (%)			28%
59	**ROI – comparable to a post tax WACC**			2.82%

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

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sch ref

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

62

63 **Opening RIV** N/A

64

65

sch ref		Line charge revenue	Expenses cash outflow	Assets commissioned	Asset disposals	Other regulated income	Monthly net cash outflows
66							
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** 3.11%

95

96 **Year-end ROI – comparable to a post tax WACC** 2.78%

97

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

99

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

101

sch ref			
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	–	
106	Other financial incentives	–	
107	**Financial incentives**		–
108			
109	**Impact of financial incentives on ROI**		–
110			
111	Input methodology claw-back	–	
112	CPP application recoverable costs	–	
113	Catastrophic event allowance	–	
114	Capex wash-up adjustment	–	
115	Transmission asset wash-up adjustment	–	
116	2013–15 NPV wash-up allowance	–	
117	Reconsideration event allowance	–	

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EDBs must provide explanatory comment on their ROI in Schedule 14 (Mandatory Explanatory Notes).
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sch ref			
118	Other wash-ups	–	
119	**Wash-up costs**		–
120			
121	**Impact of wash-up costs on ROI**		–

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SCHEDULE 3: REPORT ON REGULATORY PROFIT

This schedule requires information on the calculation of regulatory profit for the EDB for the disclosure year. All EDBs must complete all sections and provide explanatory comment on their regulatory profit in Schedule 14 (Mandatory Explanatory Notes).
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref				
7		**3(i): Regulatory Profit**		**($000)**
8		**Income**		
9		Line charge revenue		35,779
10	*plus*	Gains / (losses) on asset disposals		(271)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)		169
12				
13		**Total regulatory income**		35,677
14		**Expenses**		
15	*less*	Operational expenditure		11,454
16				
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups		12,472
18				
19		**Operating surplus / (deficit)**		11,751
20				
21	*less*	Total depreciation		6,984
22				
23	*plus*	Total revaluations		2,650
24				
25		**Regulatory profit / (loss) before tax**		7,417
26				
27	*less*	Term credit spread differential allowance		–
28				
29	*less*	Regulatory tax allowance		1,939
30				
31		**Regulatory profit/(loss) including financial incentives and wash-ups**		5,477
32				
33		**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	**($000)**	
34		**Pass through costs**		
35		Rates	170	
36		Commerce Act levies	77	
37		Industry levies	148	
38		CPP specified pass through costs	–	
39		**Recoverable costs excluding financial incentives and wash-ups**		
40		Electricity lines service charge payable to Transpower	9,322	
41		Transpower new investment contract charges	1,244	
42		System operator services	–	
43		Distributed generation allowance	1,511	
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**		12,472
47				

Company Name	**Network Tasman Limited**
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SCHEDULE 3: REPORT ON REGULATORY PROFIT

This schedule requires information on the calculation of regulatory profit for the EDB for the disclosure year. All EDBs must complete all sections and provide explanatory comment on their regulatory profit in Schedule 14 (Mandatory Explanatory Notes).
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sch ref				
48	**3(iii): Incremental Rolling Incentive Scheme**		**($000)**	
49			**CY-1**	**CY**
50			**31 Mar 20**	**31 Mar 21**
51	Allowed controllable opex		–	–
52	Actual controllable opex		–	–
53				
54	Incremental change in year			–
55				
56			**Previous years' incremental change**	**Previous years' incremental change adjusted for inflation**
57	CY-5	31 Mar 16	–	–
58	CY-4	31 Mar 17	–	–
59	CY-3	31 Mar 18	–	–
60	CY-2	31 Mar 19	–	–
61	CY-1	31 Mar 20	–	–
62	**Net incremental rolling incentive scheme**			–
63				
64	**Net recoverable costs allowed under incremental rolling incentive scheme**			–
65	**3(iv): Merger and Acquisition Expenditure**			
70				**($000)**
66	Merger and acquisition expenditure			–
67				
68	*Provide commentary on the benefits of merger and acquisition expenditure to the electricity distribution business, including required disclosures in accordance with section 2.7, in Schedule 14 (Mandatory Explanatory Notes)*			
69	**3(v): Other Disclosures**			
70				**($000)**
71	Self-insurance allowance			–

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

This schedule requires information on the calculation of the Regulatory Asset Base (RAB) value to the end of this disclosure year. This informs the ROI calculation in Schedule 2.
EDBs must provide explanatory comment on the value of their RAB in Schedule 14 (Mandatory Explanatory Notes). This information is part of audited disclosure information (as defined in section 1.4 of 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)

	RAB	**RAB**	**RAB**	**RAB**	**RAB**
for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
	($000)	**($000)**	**($000)**	**($000)**	**($000)**
Total opening RAB value	163,098	164,637	165,522	165,472	174,395
less **Total depreciation**	6,779	6,954	6,807	6,984	6,984
plus **Total revaluations**	3,531	1,808	2,452	4,187	2,650
plus **Assets commissioned**	5,612	6,386	6,557	12,075	8,066
less **Asset disposals**	825	355	393	332	847
plus **Lost and found assets adjustment**	–	–	–	–	–
plus **Adjustment resulting from asset allocation**	–	–	(1,859)	(23)	26
Total closing RAB value	164,637	165,522	165,472	174,395	177,306

4(ii): Unallocated Regulatory Asset Base

	Unallocated RAB *		**RAB**	
	($000)	**($000)**	**($000)**	**($000)**
Total opening RAB value		176,323		174,395
less				
Total depreciation		7,071		6,984
plus				
Total revaluations		2,679		2,650
plus				
Assets commissioned (other than below)	8,163		8,066	
Assets acquired from a regulated supplier	–		–	
Assets acquired from a related party	–		–	
Assets commissioned		8,163		8,066
less				
Asset disposals (other than below)	989		847	
Asset disposals to a regulated supplier	–		–	
Asset disposals to a related party	–		–	
Asset disposals		989		847
plus **Lost and found assets adjustment**		–		–
plus **Adjustment resulting from asset allocation**				26
Total closing RAB value		179,105		177,306

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

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

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

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

sch ref						
51						
52		**4(iii): Calculation of Revaluation Rate and Revaluation of Assets**				
53						
54		CPI_4				1,068
55		CPI_4^{-4}				1,052
56		Revaluation rate (%)				1.52%
57						
58			**Unallocated RAB ***		**RAB**	
59			**($000)**	**($000)**	**($000)**	**($000)**
60		Total opening RAB value	176,323		174,395	
61	*less*	Opening value of fully depreciated, disposed and lost assets	151		149	
62						
63		Total opening RAB value subject to revaluation	176,172		174,246	
64		**Total revaluations**		2,679		2,650
65						
66		**4(iv): Roll Forward of Works Under Construction**				
67			**Unallocated works under construction**		**Allocated works under construction**	
68		**Works under construction—preceding disclosure year**		5,925		6,027
69	*plus*	Capital expenditure	10,098		10,098	
70	*less*	Assets commissioned	8,163		8,066	
71	*plus*	Adjustment resulting from asset allocation			(118)	
72		**Works under construction - current disclosure year**		7,860		7,941
73						
74		Highest rate of capitalised finance applied				–
75						

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

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

sch ref

76 ### 4(v): Regulatory Depreciation

sch ref		Unallocated RAB *		RAB	
78		($000)	($000)	($000)	($000)
79	Depreciation - standard	6,958		6,859	
80	Depreciation - no standard life assets	113		125	
81	Depreciation - modified life assets	–		–	
82	Depreciation - alternative depreciation in accordance with CPP	–		–	
83	**Total depreciation**		7,071		6,984
84					

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

($000 unless otherwise specified)

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

95 ** include additional rows if needed*

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

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

sch ref			Subtransmission lines	Subtransmission cables	Zone substations	Distribution and LV lines	Distribution and LV cables	Distribution substations and transformers	Distribution switchgear	Other network assets	Non-network assets	Total
99		**Total opening RAB value**	8,062	9,371	25,818	25,712	55,007	25,369	9,525	11,977	3,554	174,395
100	*less*	Total depreciation	289	205	757	1,896	1,596	1,163	416	635	27	6,984
101	*plus*	Total revaluations	123	141	392	391	837	386	145	182	53	2,650
102	*plus*	Assets commissioned	118	1,223	137	1,859	1,714	1,628	631	377	379	8,066
103	*less*	Asset disposals	1	–	–	217	1	152	–	31	445	847
104	*plus*	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
105	*plus*	Adjustment resulting from asset allocation	–	–	–	(6)	–	–	–	–	32	26
106	*plus*	Asset category transfers	–	–	–	–	–	–	1	(1)	–	–
107		**Total closing RAB value**	8,013	10,530	25,590	25,843	55,961	26,068	9,886	11,869	3,546	177,306
108												
109		**Asset Life**										
110		Weighted average remaining asset life	39.1	45.9	34.7	46.3	46.6	42.2	41.6	16.8	20.9	(years)
111		Weighted average expected total asset life	61.1	56.3	47.6	70.6	64.2	61.7	53.7	34.7	27.1	(years)

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SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

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

sch ref					
7		**5a(i): Regulatory Tax Allowance**		**($000)**	
8		**Regulatory profit / (loss) before tax**		7,417	
9					
10	*plus*	Income not included in regulatory profit / (loss) before tax but taxable	–		*
11		Expenditure or loss in regulatory profit / (loss) before tax but not deductible	66		*
12		Amortisation of initial differences in asset values	3,239		
13		Amortisation of revaluations	863		
14				4,168	
15					
16	*less*	Total revaluations	2,650		
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	2,008		
21				4,658	
22					
23		**Regulatory taxable income**		6,926	
24					
25	*less*	Utilised tax losses	–		
26		Regulatory net taxable income		6,926	
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**		1,939	
30					
31	*	Workings to be provided in Schedule 14			
32		**5a(ii): Disclosure of Permanent Differences**			
33		In Schedule 14, Box 5, provide descriptions and workings of items recorded in the asterisked categories in Schedule 5a(i).			
34		**5a(iii): Amortisation of Initial Difference in Asset Values**		**($000)**	
35					
36		Opening unamortised initial differences in asset values	75,649		
37	*less*	Amortisation of initial differences in asset values	3,239		
38	*plus*	Adjustment for unamortised initial differences in assets acquired	–		
39	*less*	Adjustment for unamortised initial differences in assets disposed	9		
40		Closing unamortised initial differences in asset values		72,402	
41					
42		Opening weighted average remaining useful life of relevant assets (years)		23	
43					

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SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

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

sch ref				
44	**5a(iv): Amortisation of Revaluations**			**($000)**
46		Opening sum of RAB values without revaluations	155,981	
48		Adjusted depreciation	6,121	
49		Total depreciation	6,984	
50		Amortisation of revaluations		863
52	**5a(v): Reconciliation of Tax Losses**			**($000)**
54		**Opening tax losses**	–	
55	*plus*	Current period tax losses	–	
56	*less*	Utilised tax losses	–	
57		**Closing tax losses**		–
58	**5a(vi): Calculation of Deferred Tax Balance**			**($000)**
60		**Opening deferred tax**	(2,474)	
62	*plus*	Tax effect of adjusted depreciation	1,714	
64	*less*	Tax effect of tax depreciation	1,783	
66	*plus*	Tax effect of other temporary differences*	(19)	
68	*less*	Tax effect of amortisation of initial differences in asset values	907	
70	*plus*	Deferred tax balance relating to assets acquired in the disclosure year	–	
72	*less*	Deferred tax balance relating to assets disposed in the disclosure year	(218)	
74	*plus*	Deferred tax cost allocation adjustment	39	
76		**Closing deferred tax**		(3,213)
78	**5a(vii): Disclosure of Temporary Differences**			
79		*In Schedule 14, Box 6, provide descriptions and workings of items recorded in the asterisked category in Schedule 5a(vi) (Tax effect of other temporary differences).*		
81	**5a(viii): Regulatory Tax Asset Base Roll-Forward**			
82				**($000)**
83		**Opening sum of regulatory tax asset values**	69,773	
84	*less*	Tax depreciation	6,368	
85	*plus*	Regulatory tax asset value of assets commissioned	8,162	
86	*less*	Regulatory tax asset value of asset disposals	69	
87	*plus*	Lost and found assets adjustment	–	
88	*plus*	Adjustment resulting from asset allocation	165	
89	*plus*	Other adjustments to the RAB tax value	–	
90		**Closing sum of regulatory tax asset values**		71,663

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SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

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

sch ref			
7	**5b(i): Summary—Related Party Transactions**	**($000)**	**($000)**
8	**Total regulatory income**		76
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**		–

36	**5b(iii): Total Opex and Capex Related Party Transactions**		
37	**Name of related party**	**Nature of opex or capex service provided**	**Total value of transactions ($000)**
38	-	[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**		–
54	** include additional rows if needed*		
55			

Company Name	**Network Tasman Limited**
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SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

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

sch ref

7

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

9

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

17

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

19

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

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2021**

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

sch ref		Value allocated ($000s)				
7	**5d(i): Operating Cost Allocations**					
8						
9		**Arm's length deduction**	**Electricity distribution services**	**Non-electricity distribution services**	**Total**	**OVABAA allocation increase ($000s)**
10	**Service interruptions and emergencies**					
11	Directly attributable		1,115			
12	Not directly attributable	–	–	–	–	–
13	**Total attributable to regulated service**		1,115			
14	**Vegetation management**					
15	Directly attributable		1,224			
16	Not directly attributable	–	–	–	–	–
17	**Total attributable to regulated service**		1,224			
18	**Routine and corrective maintenance and inspection**					
19	Directly attributable		1,906			
20	Not directly attributable	–	–	–	–	–
21	**Total attributable to regulated service**		1,906			
22	**Asset replacement and renewal**					
23	Directly attributable		2,151			
24	Not directly attributable	–	–	–	–	–
25	**Total attributable to regulated service**		2,151			
26	**System operations and network support**					
27	Directly attributable		2,807			
28	Not directly attributable	–	–	–	–	–
29	**Total attributable to regulated service**		2,807			
30	**Business support**					
31	Directly attributable		552			
32	Not directly attributable	–	1,698	841	2,539	–
33	**Total attributable to regulated service**		2,250			
34						
35	**Operating costs directly attributable**		9,755			
36	**Operating costs not directly attributable**	–	1,698	841	2,539	–
37	**Operational expenditure**		11,453			
38						

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2021**

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref

39 ### 5d(ii): Other Cost Allocations

sch ref		($000)
40	**Pass through and recoverable costs**	
41	**Pass through costs**	
42	Directly attributable	393
43	Not directly attributable	3
44	**Total attributable to regulated service**	396
45	**Recoverable costs**	
46	Directly attributable	12,078
47	Not directly attributable	–
48	**Total attributable to regulated service**	12,078
49		

50 ### 5d(iii): Changes in Cost Allocations* †

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

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

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2021**

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

5e(i): Regulated Service Asset Values

	Value allocated ($000s) Electricity distribution services
Subtransmission lines	
Directly attributable	8,013
Not directly attributable	–
Total attributable to regulated service	8,013
Subtransmission cables	
Directly attributable	10,530
Not directly attributable	–
Total attributable to regulated service	10,530
Zone substations	
Directly attributable	25,590
Not directly attributable	–
Total attributable to regulated service	25,590
Distribution and LV lines	
Directly attributable	23,964
Not directly attributable	1,879
Total attributable to regulated service	25,843
Distribution and LV cables	
Directly attributable	55,961
Not directly attributable	–
Total attributable to regulated service	55,961
Distribution substations and transformers	
Directly attributable	26,068
Not directly attributable	–
Total attributable to regulated service	26,068
Distribution switchgear	
Directly attributable	9,886
Not directly attributable	–
Total attributable to regulated service	9,886
Other network assets	
Directly attributable	11,804
Not directly attributable	65
Total attributable to regulated service	11,869
Non-network assets	
Directly attributable	1,071
Not directly attributable	2,475
Total attributable to regulated service	3,546
Regulated service asset value directly attributable	172,887
Regulated service asset value not directly attributable	4,419
Total closing RAB value	177,306

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

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

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

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

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

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2021**

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				
7		**6a(i): Expenditure on Assets**	**($000)**	**($000)**
8		Consumer connection		690
9		System growth		3,537
10		Asset replacement and renewal		3,312
11		Asset relocations		367
12		Reliability, safety and environment:		
13		Quality of supply	906	
14		Legislative and regulatory	247	
15		Other reliability, safety and environment	94	
16		**Total reliability, safety and environment**		1,247
17		**Expenditure on network assets**		9,153
18		Expenditure on non-network assets		444
19				
20		**Expenditure on assets**		9,597
21	*plus*	Cost of financing		–
22	*less*	Value of capital contributions		27
23	*plus*	Value of vested assets		528
24				
25		**Capital expenditure**		10,098
26		**6a(ii): Subcomponents of Expenditure on Assets (where known)**		**($000)**
27		Energy efficiency and demand side management, reduction of energy losses		2
28		Overhead to underground conversion		668
29		Research and development		2
30		**6a(iii): Consumer Connection**		
31		*Consumer types defined by EDB**	**($000)**	**($000)**
32		Consumers 20kVA and less	266	
33		Consumers greater than 20kVA	424	
34		–	–	
35		–	–	
36		–	–	
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		690
39				
40	*less*	Capital contributions funding consumer connection expenditure	5	
41		**Consumer connection less capital contributions**		685
42		**6a(iv): System Growth and Asset Replacement and Renewal**		**Asset Replacement and**
43			**System Growth**	**Renewal**
44			**($000)**	**($000)**
45		Subtransmission	1,368	279
46		Zone substations	–	1,898
47		Distribution and LV lines	695	328
48		Distribution and LV cables	314	338
49		Distribution substations and transformers	375	96
50		Distribution switchgear	30	140
51		Other network assets	755	233
52		**System growth and asset replacement and renewal expenditure**	3,537	3,312
53	*less*	Capital contributions funding system growth and asset replacement and renewal	10	12
54		**System growth and asset replacement and renewal less capital contributions**	3,527	3,300
55				
56		**6a(v): Asset Relocations**		
57		*Project or programme**	**($000)**	**($000)**
58		–	–	
59		–	–	
60		–	–	
61		–	–	
62		–	–	
63		** include additional rows if needed*		
64		All other projects or programmes - asset relocations	367	
65		**Asset relocations expenditure**		367
66	*less*	Capital contributions funding asset relocations	–	
67		**Asset relocations less capital contributions**		367

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2021**

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

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

sch ref			($000)	($000)
68				
69		**6a(vi): Quality of Supply**		
70		*Project or programme**	**($000)**	**($000)**
71		–	–	
72		–	–	
73		–	–	
74		–	–	
75		–	–	
76		** include additional rows if needed*		
77		All other projects programmes - quality of supply	906	
78		**Quality of supply expenditure**		906
79	*less*	Capital contributions funding quality of supply	–	
80		**Quality of supply less capital contributions**		906
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	247	
90		**Legislative and regulatory expenditure**		247
91	*less*	Capital contributions funding legislative and regulatory	–	
92		**Legislative and regulatory less capital contributions**		247
93		**6a(viii): Other Reliability, Safety and Environment**		
94		*Project or programme**	**($000)**	**($000)**
95		–	–	
96		–	–	
97		–	–	
98		–	–	
99		–	–	
100		** include additional rows if needed*		
101		All other projects or programmes - other reliability, safety and environment	94	
102		**Other reliability, safety and environment expenditure**		94
103	*less*	Capital contributions funding other reliability, safety and environment	–	
104		**Other reliability, safety and environment less capital contributions**		94
105				
106		**6a(ix): Non-Network Assets**		
107		**Routine expenditure**		
108		*Project or programme**	**($000)**	**($000)**
109		Land & Buildings	90	
110		IT	316	
111		Vehicles, Plant & Equipment	38	
112		–	–	
113		–	–	
114		** include additional rows if needed*		
115		All other projects or programmes - routine expenditure	–	
116		**Routine expenditure**		444
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**		444

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2021**

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

sch ref			
7	**6b(i): Operational Expenditure**	**($000)**	**($000)**
8	Service interruptions and emergencies	1,115	
9	Vegetation management	1,224	
10	Routine and corrective maintenance and inspection	1,906	
11	Asset replacement and renewal	2,151	
12	**Network opex**		6,396
13	System operations and network support	2,807	
14	Business support	2,251	
15	**Non-network opex**		5,058
16			
17	**Operational expenditure**		11,454
18	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
19	Energy efficiency and demand side management, reduction of energy losses		84
20	Direct billing*		–
21	Research and development		–
22	Insurance		355
23	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**Network Tasman Limited**
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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	36,317	35,779	(1%)
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	640	690	8%
11	System growth	3,493	3,537	1%
12	Asset replacement and renewal	3,133	3,312	6%
13	Asset relocations	600	367	(39%)
14	Reliability, safety and environment:			
15	Quality of supply	585	906	55%
16	Legislative and regulatory	700	247	(65%)
17	Other reliability, safety and environment	555	94	(83%)
18	**Total reliability, safety and environment**	1,840	1,247	(32%)
19	**Expenditure on network assets**	9,706	9,153	(6%)
20	Expenditure on non-network assets	604	444	(26%)
21	Expenditure on assets	10,310	9,597	(7%)
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	1,102	1,115	1%
24	Vegetation management	1,209	1,224	1%
25	Routine and corrective maintenance and inspection	2,198	1,906	(13%)
26	Asset replacement and renewal	1,730	2,151	24%
27	**Network opex**	6,239	6,396	3%
28	System operations and network support	2,778	2,807	1%
29	Business support	2,381	2,251	(5%)
30	**Non-network opex**	5,159	5,058	(2%)
31	**Operational expenditure**	11,398	11,454	0%
32	**7(iv): Subcomponents of Expenditure on Assets (where known)**			
33	Energy efficiency and demand side management, reduction of energy losses	–	2	–
34	Overhead to underground conversion	600	668	11%
35	Research and development	–	2	–
36				
37	**7(v): Subcomponents of Operational Expenditure (where known)**			
38	Energy efficiency and demand side management, reduction of energy losses	45	84	87%
39	Direct billing	–	–	–
40	Research and development	–	–	–
41	Insurance	347	355	2%
42				

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

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

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2021**
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

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)	**Price component** 0STL	0UNM	1RLANY	1RLDAY	1RLNIT	1RLWSR	1RLGEN	1RSANY
				Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	Watts	day	kWh	kWh	kWh	kWh	kWh	kWh
0S	Streetlamps	Standard	–	1,809	430,690	–	–	–	–	–	–	–
0UNM	Unmetered Supplies	Standard	–	14	–	75	–	–	–	–	–	–
1RL	15 kVA Capacity	Standard	18,516	104,003	–	–	73,876	1,435	1,538	27,154	1,623	–
1RS	15 kVA Capacity	Standard	15,520	142,291	–	–	–	–	–	–	–	104,376
1GL	15 kVA Capacity	Standard	3,529	20,626	–	–	–	–	–	–	–	–
2	20 - 150 kVA Capacity	Standard	2,740	95,057	–	–	–	–	–	–	–	–
2HLFC	or 30 kVA Capacity	Standard	5	23	–	–	–	–	–	–	–	–
2LLFC	150kVA Capacity	Standard	52	457	–	–	–	–	–	–	–	–
HLF	150kVA Capacity	Standard	52	9,675	–	–	–	–	–	–	–	–
3.1	3000kVA	Standard	4	9,339	–	–	–	–	–	–	–	–
3.3	3000kVA	Standard	6	8,942	–	–	–	–	–	–	–	–
3.4	3000kVA	Standard	169	121,152	–	–	–	–	–	–	–	–
3.5	3000kVA	Standard	2	12,815	–	–	–	–	–	–	–	–
6.1	> 3000,	Non-standard	1	88,290	–	–	–	–	–	–	–	–
6.2	> 3000,	Non-standard	1	14,031	–	–	–	–	–	–	–	–
CB	Cobb River Hydro	Non-standard	1	2	–	–	–	–	–	–	–	–
MAT	Matiri Hydro	Non-standard	1	–	–	–	–	–	–	–	–	–
Connections	-	Standard	–	–	–	–	–	–	–	–	–	–
Solar Connections	-	Standard	–	–	–	–	–	–	–	–	–	–
0	-	[Select one]	–	–	–	–	–	–	–	–	–	–
Add extra rows for additional consumer groups or price category codes as necessary												
		Standard consumer totals	40,593	526,203	430,690	75	73,876	1,435	1,538	27,154	1,623	104,376
		Non-standard consumer totals	4	102,323	–	–	–	–	–	–	–	–
		Total for all consumers	40,597	628,526	430,690	75	73,876	1,435	1,538	27,154	1,623	104,376

SCHEDULE 8: REPORT ON BILLED QUANTITIE!

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

sch ref

8 **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	2LANY
				kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh
15	0S	Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
16	0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
17	1RL	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
18	1RS	15 kVA Capacity	Standard	2,281	2,369	33,265	1,092	–	–	–	–	–	–	–	–	–	–	–
19	1GL	15 kVA Capacity	Standard	–	–	–	–	17,867	722	440	1,597	70	–	–	–	–	–	–
20	2	20 - 150 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	66,599	17,606	7,585	3,267	692	–
21	2HLFC	or 30 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
22	2LLFC	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	346
23	HLF	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
24	3.1	3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
25	3.3	3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
26	3.4	3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
27	3.5	3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
28	6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
29	6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
30	CB	Cobb River Hydro	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	MAT	Matiri Hydro	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Connections	-	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Solar Connections	-	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	0	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
33	*Add extra rows for additional consumer groups or price categ*																	
34			**Standard consumer totals**	2,281	2,369	33,265	1,092	17,867	722	440	1,597	70	66,599	17,606	7,585	3,267	692	346
35			**Non-standard consumer totals**	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
36			**Total for all consumers**	2,281	2,369	33,265	1,092	17,867	722	440	1,597	70	66,599	17,606	7,585	3,267	692	346

SCHEDULE 8: REPORT ON BILLED QUANTITIE

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

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)	2LDAY	2LNIT	2LWSR	2LGEN	2HANY	2HDAY	2HNIT	2HWSR	2HGEN	HLFANY	HLFDAY	HLFNIT	HLFWSR	HLFGEN	1RL
			kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	Daily
0S	Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
1RL	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	18,589
1RS	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
1GL	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
2	20 - 150 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
2HLFC	or 30 kVA Capacity	Standard	–	–	–	–	13	–	–	10	–	–	–	–	–	–	–
2LLFC	150kVA Capacity	Standard	40	17	54	8	–	–	–	–	–	–	–	–	–	–	–
HLF	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	4,593	3,583	1,465	34	21	–
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 categ																	
		Standard consumer totals	40	17	54	8	13	–	–	10	–	4,593	3,583	1,465	34	21	18,589
		Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
		Total for all consumers	40	17	54	8	13	–	–	10	–	4,593	3,583	1,465	34	21	18,589

SCHEDULE 8: REPORT ON BILLED QUANTITIE!

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

sch ref

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

9

10

11

sch ref	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	1RS	1GL	2	2HLFC	2LLFC	HLF	AnyDem31	AnyDem33	AnyDem34	AnyDem35	WinDem	kVAr	SD31	SN31	WD31
13				Daily	Daily	Capacity	Daily	Daily	kVA	kVA	kVA	kVA	kVA	kW	kVAr	kWh	kWh	kWh
14																		
15	0S	Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
16	0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
17	1RL	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
18	1RS	15 kVA Capacity	Standard	13,334	–	–	–	–	–	–	–	–	–	–	–	–	–	–
19	1GL	15 kVA Capacity	Standard	–	3,066	–	–	–	–	–	–	–	–	–	–	–	–	–
20	2	20 - 150 kVA Capacity	Standard	–	–	108,414	–	–	–	–	–	–	–	–	–	–	–	–
21	2HLFC	or 30 kVA Capacity	Standard	–	–	–	5	–	–	–	–	–	–	–	–	–	–	–
22	2LLFC	150kVA Capacity	Standard	–	–	–	–	124	–	–	–	–	–	–	–	–	–	–
23	HLF	150kVA Capacity	Standard	–	–	–	–	–	2,665	–	–	–	–	–	–	–	–	–
24	3.1	3000kVA	Standard	–	–	–	–	–	–	2,192	–	–	–	1,566	–	4,030	1,661	2,565
25	3.3	3000kVA	Standard	–	–	–	–	–	–	–	2,479	–	–	1,145	–	–	–	–
26	3.4	3000kVA	Standard	–	–	–	–	–	–	–	–	47,005	–	21,995	97	–	–	–
27	3.5	3000kVA	Standard	–	–	–	–	–	–	–	–	–	3,600	1,989	–	–	–	–
28	6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
29	6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
30	CB	Cobb River Hydro	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	MAT	Matiri Hydro	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Connections	-	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Solar Connections	-	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	0	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
33	*Add extra rows for additional consumer groups or price categ*																	
34			**Standard consumer totals**	13,334	3,066	108,414	5	124	2,665	2,192	2,479	47,005	3,600	26,696	97	4,030	1,661	2,565
35			**Non-standard consumer totals**	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
36			**Total for all consumers**	13,334	3,066	108,414	5	124	2,665	2,192	2,479	47,005	3,600	26,696	97	4,030	1,661	2,565

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SCHEDULE 8: REPORT ON BILLED QUANTITIES

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

sch ref

8 8(i): Billed Quantities by Price Component

sch ref	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	WN31	SD33	SN33	WD33	WN33	SD34	SN34	WD34	WN34	SD35	SN35	WD35	WN35	3.1GEN	3.3GEN
13				kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh
15	0S	Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
16	0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
17	1RL	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
18	1RS	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
19	1GL	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
20	2	20 - 150 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
21	2HLFC	or 30 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
22	2LLFC	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
23	HLF	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
24	3.1	3000kVA	Standard	1,083	–	–	–	–	–	–	–	–	–	–	–	–	–	–
25	3.3	3000kVA	Standard	–	3,914	1,786	2,305	937	–	–	–	–	–	–	–	–	–	2,016
26	3.4	3000kVA	Standard	–	–	–	–	–	49,478	17,844	39,419	14,411	–	–	–	–	–	–
27	3.5	3000kVA	Standard	–	–	–	–	–	–	–	–	–	4,667	2,081	4,215	1,852	–	–
28	6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
29	6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
30	CB	Cobb River Hydro	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	MAT	Matiri Hydro	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Connections	-	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Solar Connections	-	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	0	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
33	*Add extra rows for additional consumer groups or price categ*																	
34			**Standard consumer totals**	1,083	3,914	1,786	2,305	937	49,478	17,844	39,419	14,411	4,667	2,081	4,215	1,852	–	2,016
35			**Non-standard consumer totals**	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
36			**Total for all consumers**	1,083	3,914	1,786	2,305	937	49,478	17,844	39,419	14,411	4,667	2,081	4,215	1,852	–	2,016

SCHEDULE 8: REPORT ON BILLED QUANTITIE!

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

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)	3.4GEN kWh	3.4GEN kWh	6.1 Annual	6.2 Annual	NDL kVA=km	NCA Admin G0 New connection application	NCA Admin G1 New connection application	NCA Admin G2 New connection application	NCA Admin G3 New connection application	CB Annual	MAT Annual	Standard DG Part1A Per application	Standard DG Part1 Per application	DG >10kw <100kW Per application	DG >100kw <1000kW 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	–	–	–	–	–	–	–	–	–	–	–	–	–	–
3.5	3000kVA	Standard	–	3	–	–	–	–	–	–	–	–	–	–	–	–	–
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	–	–	–	–	30,361	–	–	–	–	–	–	–	–	–	–
Solar Connections	-	Standard	–	–	–	–	–	–	838	48	11	–	–	233	1	13	–
0	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Add extra rows for additional consumer groups or price categ																	
		Standard consumer totals	3	3	–	–	30,361	–	838	48	11	–	–	233	1	13	–
		Non-standard consumer totals	–	–	1	1	–	–	–	–	–	–	–	–	–	–	–
		Total for all consumers	3	3	1	1	30,361	–	838	48	11	–	–	233	1	13	–

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2021**
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.

39 **8(ii): Line Charge Revenues ($000) by Price Component**

Row	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)		Line charge revenues ($000) by price component							
42								Price component	0STL	0UNM	1RLANY	1RLDAY	1RLNIT	1RLWSR	1RLGEN	1RSANY
43								Rate (eg, $ per day, $ per kWh, etc.)	0.00119	0.533	0.0734	0.0804	0.0129	0.0196	0	0.0245
	0S	Streetlamps	Standard	$176	–	$136	$39		$176	–	–	–	–	–	–	–
46	0UNM	Unmetered Supplies	Standard	$14	–	$11	$3		–	$14	–	–	–	–	–	–
47	1RL	15 kVA Capacity	Standard	$6,513	$2,870	$4,269	$2,243		–	–	$4,902	$105	$17	$471	–	–
48	1RS	15 kVA Capacity	Standard	$7,920	$3,799	$5,094	$2,827		$1	–	–	–	–	–	–	$2,721
49	1GL	15 kVA Capacity	Standard	$1,624	$614	$1,099	$525		$2	–	–	–	–	–	–	–
50	2	20 - 150 kVA Capacity	Standard	$7,254	$2,667	$5,158	$2,095		$3	–	–	–	–	–	–	–
51	2HLFC	or 30 kVA Capacity	Standard	$5	$1	$4	$1		–	–	–	–	–	–	–	–
52	2LLFC	150kVA Capacity	Standard	$57	$12	$48	$9		–	–	–	–	–	–	–	–
53	HLF	150kVA Capacity	Standard	$524	$188	$418	$107		–	–	–	–	–	–	–	–
54	3.1	3000kVA	Standard	$292	$31	$126	$166		–	–	–	–	–	–	–	–
55	3.3	3000kVA	Standard	$351	$83	$220	$132		–	–	–	–	–	–	–	–
56	3.4	3000kVA	Standard	$6,421	$1,320	$3,898	$2,523		–	–	–	–	–	–	–	–
57	3.5	3000kVA	Standard	$522	$107	$301	$221		–	–	–	–	–	–	–	–
58	6.1	> 3000,	Non-standard	$1,449	$27	$200	$1,249		–	–	–	–	–	–	–	–
59	6.2	> 3000,	Non-standard	$469	$40	$203	$265		–	–	–	–	–	–	–	–
	CB	-	Non-standard	$1,690	–	$1,405	$284		–	–	–	–	–	–	–	–
	MAT	MAT, CB, EG etc	Non-standard	$3	–	$1	$2		–	–	–	–	–	–	–	–
60	Connections	-	Standard	$464	–	$464	–		–	–	–	–	–	–	–	–
61	Solar Connections	-	Standard	$30	–	$30	–		–	–	–	–	–	–	–	–
62	*Add extra rows for additional consumer groups or price category codes as necessary*															
63			**Standard consumer totals**	$32,168	$11,691	$21,276	$10,892		$181	$14	$4,902	$105	$17	$471	–	$2,721
64			**Non-standard consumer totals**	$3,610	$66	$1,810	$1,800		–	–	–	–	–	–	–	–
65			**Total for all consumers**	$35,779	$11,758	$23,086	$12,693	–	$181	$14	$4,902	$105	$17	$471	–	$2,721

67 **8(iii): Number of ICPs directly billed**

Check OK

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

SCHEDULE 8: REPORT ON BILLED QUANTITIES

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

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

			1RSDAY	1RSNIT	1RSWSR	1RSGEN	1GLANY	1GLDAY	1GLNIT	1GLWSR	1GLGEN	2ANY	2DAY	2NIT	2WSR	2GEN	2LANY
Consumer group name or price category code	**Consumer type or types (eg, residential, commercial etc.)**	**Standard or non-standard consumer group (specify)**	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	0.1316
0S	Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
1RL	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
1RS	15 kVA Capacity	Standard	$72	$12	$247	–	–	–	–	–	–	–	–	–	–	–	–
1GL	15 kVA Capacity	Standard	–	–	–	–	$466	$23	$2	$12	–	–	–	–	–	–	–
2	20 - 150 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	$2,593	$784	$97	$56	–	–
2HLFC	or 30 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
2LLFC	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	$41
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 categ																	
		Standard consumer totals	$72	$12	$247	–	$466	$23	$2	$12	–	$2,593	$784	$97	$56	–	$41
		Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
		Total for all consumers	$72	$12	$247	–	$466	$23	$2	$12	–	$2,593	$784	$97	$56	–	$41

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	4

SCHEDULE 8: REPORT ON BILLED QUANTITIES

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

39 ### 8(ii): Line Charge Revenues ($000) by Price Co

Row	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	2LDAY	2LNIT	2LWSR	2LGEN	2HANY	2HDAY	2HNIT	2HWSR	2HGEN	HLFANY	HLFDAY	HLFNIT	HLFWSR	HLFGEN	1RL
43				0.1498	0.0507	0.0572	0	0.262	0.2844	0.1428	0.1701	0	0.0079	0.009	0.0019	0.0017	0	0.15
	0S	Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
46	0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
47	1RL	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	$1,018
48	1RS	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
49	1GL	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
50	2	20 - 150 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
51	2HLFC	or 30 kVA Capacity	Standard	–	–	–	–	$3	–	–	$2	–	–	–	–	–	–	–
52	2LLFC	150kVA Capacity	Standard	$6	$1	$3	–	–	–	–	–	–	–	–	–	–	–	–
53	HLF	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	$67	$59	$6	$0	–	–
54	3.1	3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
55	3.3	3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
56	3.4	3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
57	3.5	3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
58	6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
59	6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	CB	-	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	MAT	MAT, CB, EG etc	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
60	Connections	-	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
61	Solar Connections	-	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
62	*Add extra rows for additional consumer groups or price categ*																	
63			**Standard consumer totals**	$6	$1	$3	–	$3	–	–	$2	–	$67	$59	$6	$0	–	$1,018
64			**Non-standard consumer totals**	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
65			**Total for all consumers**	$6	$1	$3	–	$3	–	–	$2	–	$67	$59	$6	$0	–	$1,018

67 ### 8(iii): Number of ICPs directly billed

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

SCHEDULE 8: REPORT ON BILLED QUANTITIE!

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

39 **8(ii): Line Charge Revenues ($000) by Price Co**

Row	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	1RS	1GL	2	2HLFC	2LLFC	HLF	AnyDem31	AnyDem33	AnyDem34	AnyDem35	WinDem	kVAr	SD31	SN31	WD31
43				1	1	0.094	0.15	0.15	0.4032	0.1276	0.1462	0.154	0.1462	0.281	0.2899	0.0031	0.0015	0.0056
	0S	Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
46	0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
47	1RL	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
48	1RS	15 kVA Capacity	Standard	$4,867	–	–	–	–	–	–	–	–	–	–	–	–	–	–
49	1GL	15 kVA Capacity	Standard	–	$1,119	–	–	–	–	–	–	–	–	–	–	–	–	–
50	2	20 - 150 kVA Capacity	Standard	–	–	$3,720	–	–	–	–	–	–	–	–	–	–	–	–
51	2HLFC	or 30 kVA Capacity	Standard	–	–	–	$0	–	–	–	–	–	–	–	–	–	–	–
52	2LLFC	150kVA Capacity	Standard	–	–	–	–	$7	–	–	–	–	–	–	–	–	–	–
53	HLF	150kVA Capacity	Standard	–	–	–	–	–	$392	–	–	–	–	–	–	–	–	–
54	3.1	3000kVA	Standard	–	–	–	–	–	–	$102	–	–	–	$161	–	$12	$3	$14
55	3.3	3000kVA	Standard	–	–	–	–	–	–	–	$132	–	–	$117	–	–	–	–
56	3.4	3000kVA	Standard	–	–	–	–	–	–	–	–	$2,642	–	$2,256	$10	–	–	–
57	3.5	3000kVA	Standard	–	–	–	–	–	–	–	–	–	$192	$204	–	–	–	–
58	6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
59	6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	CB	-	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	MAT	MAT, CB, EG etc	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
60	Connections	-	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
61	Solar Connections	-	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
62	*Add extra rows for additional consumer groups or price categ*																	
63			**Standard consumer totals**	$4,867	$1,119	$3,720	$0	$7	$392	$102	$132	$2,642	$192	$2,738	$10	$12	$3	$14
64			**Non-standard consumer totals**	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
65			**Total for all consumers**	$4,867	$1,119	$3,720	$0	$7	$392	$102	$132	$2,642	$192	$2,738	$10	$12	$3	$14

67 **8(iii): Number of ICPs directly billed**

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

SCHEDULE 8: REPORT ON BILLED QUANTITIE

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

39 **8(ii): Line Charge Revenues ($000) by Price Co**

	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	WN31	SD33	SN33	WD33	WN33	SD34	SN34	WD34	WN34	SD35	SN35	WD35	WN35	3.1GEN	3.3GEN
42–43				0.0015	0.0094	0.0051	0.0242	0.0051	0.0094	0.0051	0.0242	0.0051	0.0064	0.0039	0.0206	0.0039	0	0
	0S	Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
46	0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
47	1RL	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
48	1RS	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
49	1GL	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
50	2	20 - 150 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
51	2HLFC	or 30 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
52	2LLFC	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
53	HLF	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
54	3.1	3000kVA	Standard	$2	–	–	–	–	–	–	–	–	–	–	–	–	–	–
55	3.3	3000kVA	Standard	–	$35	$9	$53	$5	–	–	–	–	–	–	–	–	–	–
56	3.4	3000kVA	Standard	–	–	–	–	–	$444	$86	$913	$70	–	–	–	–	–	–
57	3.5	3000kVA	Standard	–	–	–	–	–	–	–	–	–	$29	$8	$83	$7	–	–
58	6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
59	6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	CB	-	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	MAT	MAT, CB, EG etc	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
60	Connections	-	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
61	Solar Connections	-	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
62	*Add extra rows for additional consumer groups or price categ*																	
63			**Standard consumer totals**	$2	$35	$9	$53	$5	$444	$86	$913	$70	$29	$8	$83	$7	–	–
64			**Non-standard consumer totals**	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
65			**Total for all consumers**	$2	$35	$9	$53	$5	$444	$86	$913	$70	$29	$8	$83	$7	–	–

67 **8(iii): Number of ICPs directly billed**

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

SCHEDULE 8: REPORT ON BILLED QUANTITIE!

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

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

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	3.4GEN	3.4GEN	6.1	6.2	NDL	NCA Admin G0	NCA Admin G1	NCA Admin G2	NCA Admin G3	CB	MAT	Standard DG Part1A	Standard DG Part1	DG >10kw <100kW	DG >100kw <1000kW
			0	0	Annual	Annual	7.714143	125	250	325	400	Annual	Annual	100	200	500	1000
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	–	–	$1,449	–	–	–	–	–	–	–	–	–	–	–	–
6.2	> 3000,	Non-standard	–	–	–	$469	–	–	–	–	–	–	–	–	–	–	–
CB	-	Non-standard	–	–	–	–	–	–	–	–	–	$1,690	–	–	–	–	–
MAT	MAT, CB, EG etc	Non-standard	–	–	–	–	–	–	–	–	–	–	$3	–	–	–	–
Connections	-	Standard	–	–	–	–	$234	–	$210	$16	$4	–	–	–	–	–	–
Solar Connections	-	Standard	–	–	–	–	–	–	–	–	–	–	–	$23	$0	$7	–
Add extra rows for additional consumer groups or price categ																	
		Standard consumer totals	–	–	–	–	$234	–	$210	$16	$4	–	–	$23	$0	$7	–
		Non-standard consumer totals	–	–	$1,449	$469	–	–	–	–	–	$1,690	$3	–	–	–	–
		Total for all consumers	–	–	$1,449	$469	$234	–	$210	$16	$4	$1,690	$3	$23	$0	$7	–

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	4

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2021**
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

	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
8								
9	All	Overhead Line	Concrete poles / steel structure	No.	26,242	26,579	337	3
10	All	Overhead Line	Wood poles	No.	1,668	1,692	24	3
11	All	Overhead Line	Other pole types	No.	494	437	(57)	3
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	281	281	–	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	4
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	34	34	–	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	4
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	3	3	–	4
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	4
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	4
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	4
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	4
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	4
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	15	15	–	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	4
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	4
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	9	9	–	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	4
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	102	104	2	4
29	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	4
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	9	9	–	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	20	22	2	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	95	95	–	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	8	8	–	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	25	25	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1,890	1,889	(1)	3
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	3
37	HV	Distribution Line	SWER conductor	km	–	–	–	4
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	138	147	9	3
39	HV	Distribution Cable	Distribution UG PILC	km	135	135	–	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	78	73	(5)	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1,332	1,323	(9)	3
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	146	202	56	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	129	140	11	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	3,806	3,822	16	3
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	760	789	29	3
48	HV	Distribution Transformer	Voltage regulators	No.	11	11	–	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	25	25	–	4
50	LV	LV Line	LV OH Conductor	km	497	492	(5)	3
51	LV	LV Cable	LV UG Cable	km	662	681	19	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	–	4
53	LV	Connections	OH/UG consumer service connections	No.	41,012	41,735	723	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	113	113	–	4
55	All	SCADA and communications	SCADA and communications equipment operating as a single syste	Lot	1	1	–	4
56	All	Capacitor Banks	Capacitors including controls	No	10	10	–	4
57	All	Load Control	Centralised plant	Lot	5	5	–	4
58	All	Load Control	Relays	No	–	–	–	4
59	All	Civils	Cable Tunnels	km	–	–	–	4

SCHEDULE 9b: ASSET AGE PROFILE

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

sch ref

8 **Disclosure Year (year ended)** 31 March 2021

Number of assets at disclosure year end by installation date

	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
9																							
10	All	Overhead Line	Concrete poles / steel structure	No.	2,487	1,253	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.	–	76	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.	–	–	56	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.	–	3	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	–	8	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	51	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 sectionalisers	No.	–	–	–	–	–	–	–	2	–	–	1	4	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.	13	53	140	495	469	853	589	36	77	81	64	74	45	38	22	42	45	44	34
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	4	9	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	–	23	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 syst	Lot	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	–	–	–	2	–	–	–	–	–	1	2	2	1
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**
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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 cat

sch ref

8 **Disclosure Year (year ended)** 31 March 2021

sch ref	Voltage	Asset category	Asset class	Units	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	No. with age unknown	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
9																		
10	All	Overhead Line	Concrete poles / steel structure	No.	137	128	150	203	33	130	70	100	155	117	466	26,579	–	1
11	All	Overhead Line	Wood poles	No.	15	14	29	–	–	8	42	84	93	4	255	1,692	–	1
12	All	Overhead Line	Other pole types	No.	–	1	–	–	–	–	–	–	–	–	51	437	–	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	104	–	1
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	4
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	9	–	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	–	–	–	–	–	–	95	–	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	–	–	–	–	–	–	25	–	4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	12	16	6	2	–	6	8	21	21	20	–	1,889	–	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	–	147	–	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 sectionalisers	No.	8	4	6	4	5	6	1	8	8	–	–	73	–	2
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	2
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	19	10	13	25	5	7	13	34	18	10	849	1,323	–	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	56	9	202	–	2
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	2	–	–	4	6	15	10	11	69	140	–	2
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	46	80	61	27	44	61	36	82	85	11	75	3,822	–	2
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	4	19	31	22	28	22	40	38	24	16	–	789	–	2
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	–	–	–	–	–	–	6	11	–	2
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	–	–	–	–	–	–	–	–	25	–	2
51	LV	LV Line	LV OH Conductor	km	1	–	1	–	–	1	–	–	–	–	2	492	–	2
52	LV	LV Cable	LV UG Cable	km	9	9	11	12	3	14	13	17	16	19	13	681	–	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	41,735	–	2
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	6	–	–	14	–	–	–	3	–	–	113	–	3
56	All	SCADA and communications	SCADA and communications equipment operating as a single syst	Lot	–	–	–	–	–	–	–	–	–	–	–	1	–	3
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	1	–	1	–	–	–	–	10	–	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**
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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)	1,870	282	2,152
17	Low voltage (< 1kV)	492	680	1,172
18	**Total circuit length (for supply)**	2,662	1,012	3,674
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)**	**Circuit length (km)**	**(% of total overhead length)**
24	Urban	177	7%
25	Rural	2,289	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**	2,662	100%
31			
32		**Circuit length (km)**	**(% of total circuit length)**
33	Length of circuit within 10km of coastline or geothermal areas (where known)	1,671	45%
34		**Circuit length (km)**	**(% of total overhead length)**
35	Overhead circuit requiring vegetation management	2,668	100%

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SCHEDULE 9d: REPORT ON EMBEDDED NETWORKS

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

sch ref

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

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

Company Name	**Network Tasman Limited**
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SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref				
8	**9e(i): Consumer Connections**			
9	*Number of ICPs connected in year by consumer type*			
10	*Consumer types defined by EDB**	**Number of connections (ICPs)**		
11	Consumers 20kVA and less	744		
12	Consumers greater than 20kVA	36		
13		–		
14		–		
15		–		
16	** include additional rows if needed*			
17	**Connections total**	780		
18				
19	**Distributed generation**			
20	Number of connections made in year	153	**connections**	
21	Capacity of distributed generation installed in year	0.97	**MVA**	
22	**9e(ii): System Demand**			
23				
24				
25	**Maximum coincident system demand**	**Demand at time of maximum coincident demand (MW)**		
26	GXP demand	125		
27	*plus* Distributed generation output at HV and above	5		
28	**Maximum coincident system demand**	129		
29	*less* Net transfers to (from) other EDBs at HV and above	15		
30	**Demand on system for supply to consumers' connection points**	114		
31	**Electricity volumes carried**	**Energy (GWh)**		
32	Electricity supplied from GXPs	626		
33	*less* Electricity exports to GXPs	51		
34	*plus* Electricity supplied from distributed generation	182		
35	*less* Net electricity supplied to (from) other EDBs	90		
36	**Electricity entering system for supply to consumers' connection points**	667		
37	*less* Total energy delivered to ICPs	629		
38	**Electricity losses (loss ratio)**	38	5.8%	
39				
40	**Load factor**	0.67		
41	**9e(iii): Transformer Capacity**			
42		**(MVA)**		
43	Distribution transformer capacity (EDB owned)	446		
44	Distribution transformer capacity (Non-EDB owned, estimated)	44		
45	**Total distribution transformer capacity**	490		
46				
47	**Zone substation transformer capacity**	381		

Company Name	**Network Tasman Limited**
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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

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)	151	
12	Class C (unplanned interruptions on the network)	124	
13	Class D (unplanned interruptions by Transpower)	–	
14	Class E (unplanned interruptions of EDB owned generation)	–	
15	Class F (unplanned interruptions of generation owned by others)	–	
16	Class G (unplanned interruptions caused by another disclosing entity)	–	
17	Class H (planned interruptions caused by another disclosing entity)	–	
18	Class I (interruptions caused by parties not included above)	–	
19	**Total**	276	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	88	36
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)	0.03	10.6
26	Class B (planned interruptions on the network)	0.33	116.0
27	Class C (unplanned interruptions on the network)	0.85	87.5
28	Class D (unplanned interruptions by Transpower)	–	–
29	Class E (unplanned interruptions of EDB owned generation)	–	–
30	Class F (unplanned interruptions of generation owned by others)	–	–
31	Class G (unplanned interruptions caused by another disclosing entity)	–	–
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	–	–
34	**Total**	1.21	214.1
35			
36	**Normalised SAIFI and SAIDI**	**Normalised SAIFI**	**Normalised SAIDI**
37	Classes B & C (interruptions on the network)	1.17	199.4
38			

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SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

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

Cause	SAIFI	SAIDI
Lightning	0.00	0.1
Vegetation	0.00	0.7
Adverse weather	0.04	7.0
Adverse environment	–	–
Third party interference	0.09	9.8
Wildlife	0.08	6.9
Human error	0.07	1.1
Defective equipment	0.27	31.2
Cause unknown	0.30	30.8

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.00	1.6
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	0.31	111.7
Distribution cables (excluding LV)	0.01	2.6
Distribution other (excluding LV)	–	–

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.12	16.1
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	0.62	56.1
Distribution cables (excluding LV)	0.11	15.0
Distribution other (excluding LV)	0.00	0.2

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	5	281	1.78
Subtransmission cables	–	37	–
Subtransmission other	–		
Distribution lines (excluding LV)	105	1,889	5.56
Distribution cables (excluding LV)	12	282	4.25
Distribution other (excluding LV)	2		
Total	124		

Company Name: Network Tasman Limited

For Year Ended: 31 March 2021

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 results in a relatively low return on investment. Posted discounts reduce NTL’s regulated prices/revenues and therefore return on investment when compared to distributing the same amount of money via dividends or discretionary discounts.

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 $120,000.

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 no changes in classification.

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

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

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

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

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

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

Box 5: Regulatory tax allowance: permanent differences
Expenditure or loss in regulatory profit / (loss) before tax but not deductible -

- Non-deductible expenses (non-deductible entertainment expenses)
- Movement in provisions (holiday pay, long service leave, sick leave and loss allowance)

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 $127,000 @28% = $35,600 less. Movement in provisions temporary difference $59,000 @28% = $16,500. Making temporary differences of $19,100.

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 $837,000.

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 increases the regulatory asset base by $26,000 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 $500,000 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 $50,000 due to the higher than expected level of connections.

- Asset relocations are $233,000 under target due to higher than expected contribution received for undergrounding projects.

- Asset replacement and renewal costs are $179,000 over target. This is due to the focus on light copper replacement work requiring more replacement poles than anticipated.

- Reliability, safety and environment – quality of supply is over target by $321,000. This is due to more sub earths and pole improvements than planned.

- Reliability, safety and environment – legislative and regulatory is $453,000 under target with Platform to Padmount Conversion project costing less and taking longer than expected.

- Reliability, safety and environment – Other reliability, safety and environment is under target by $461,000. This is due to the Lead Insulation Platformmount Transformer project's priority being reassessed and deferred.

- System Growth is slightly $43,000 (1%) over target.

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

- Service interruptions and emergencies costs are 1% ($13,000) over target.

- Vegetation management costs 1% ($15,000) over target.

- Routine and corrective maintenance and inspection costs are $292,000 below target.
  - The lines due for survey were shorter than in previous years therefore cost less.
  - Traffic management was less than expected as a lot of work was done in areas not in road reserve, therefore no traffic management costs.
  - The introduction of a new app reduce the costs of distribution transformer MDI reads and checks.

- Asset replacement and renewal expenditure is 24% ($421,000) higher than target. In the year ending 31 March 2021 there was a focus on reconductoring projects. During these projects, the opportunity was taken to maintain the poles.

- Non-network expenditure is $98,000 below target. This variance is spread over many expenses, none that is 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
In early 2020 NTL posted new prices for 01 April 2020. Overall there was an increase on the 2019-20 prices, primarily due to an increase in transmission (grid) charges. However during early 2020-21 as the corona-virus pandemic expanded and the economic stress it brought on many consumers, NTL decided to pay out an additional line charge discount of $0.95M. This accounts for most of the variance between the budget/target revenue and the actual revenue. 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
Reliability from unplanned outages was a little over target for the year (SAIDI 87 actual vs 75 target). The causes of the outages were a mix of the common causes, these being cars vs pole, trees felled over lines, bird strikes, broken insulators and a number of cable faults. There were no extreme weather events during the year. Reliability from planned outages was also a little over target (SAIDI 116 actual vs 100 target). The light copper conductor replacement project was a major component of these planned outages.

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

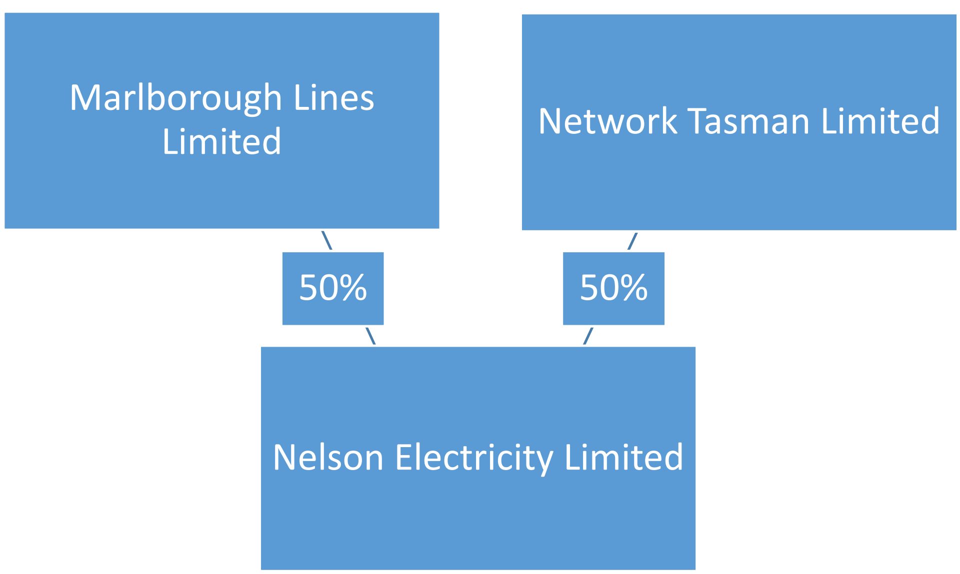
    18.2 for each error, reference to the web address where the disclosure made in accordance with clause 2.12.1 is publicly disclosed.

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 technical 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
Total Annual Charge	**27**

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.

Management fee for engineering and technical services.

> The fee is set at $49,500 per year. This was based on the number of hours estimated to be spent by Network Tasman Limited staff providing these 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.

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.

Company Name	Network Tasman Limited
For Year Ended	31 March 2021

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

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.

networktasman
Your consumer-owned electricity distributor

Network Tasman Limited
52 Main Road, Hope 7020
PO Box 3005
Richmond 7050
Nelson, New Zealand

Phone: +64 3 989 3600
Freephone: 0800 508 098
Email: info@networktasman.co.nz
Website: www.networktasman.co.nz

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

27 August 2021

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 2021 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 2021 (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**
Cost allocation The Determination and the IM Determination place a requirement on the Company to allocate indirect costs between its regulated and non-regulated business. The Company has a significant investment property portfolio, a fibre network, and a smart meter network that are not part of the regulated business. The Company does not have separate management teams, or finance and administration teams for the divisions that are not part of the regulated business. Therefore, a portion of their time needs to be allocated to the regulated business. The IM Determination sets out the rules and processes for allocating non-directly attributable costs.	We obtained an understanding of the Company's cost allocation approach to allocate indirect costs to the regulated and non-regulated business. We confirmed the approach used is in accordance with the Determination and the IM Determination. The procedures we carried out, to satisfy ourselves that indirect costs were correctly allocated, included: • reconciling the regulated and unregulated financial information to the audited financial statements for the year ended 31 March 2021, 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
	• 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.
Accuracy of the number and duration of electricity outages The Company has a combination of manual and automated systems to identify outages and to record the duration of outages. This outage information is used to prepare the Company's Report on Network Reliability in Schedule 10. If this information is inaccurate then the measures of the reliability of the network could be materially misstated. This is a key 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. There can also be significant consequences if the Company breaches the reliability thresholds. 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.	We have obtained an understanding of the Company's system to record electricity outages, and their duration. This included review of the Company's definition of interruptions, planned interruptions and major event days. Our procedures to assess the adequacy of the Company's methods to identify and record electricity outages and their duration included: • 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. With respect to the Exemption, we: • obtained and documented our understanding of the Company's methods by which electricity outages and their duration are recorded where an outage event results in successive interruptions of supply; • compared this to the documented process that the Company followed in the previous year; and • identified potential incidences of successive interruptions of supply to help provide assurance

<table>
<tr><th>Key assurance matter</th><th>How our procedures addressed the key assurance matter</th></tr>
<tr><td></td><td>that the Company’s methods, by which electricity outages and their duration are recorded where an outage event results in successive interruptions of supply, were the same for both years.

Having carried out these procedures, and assessed the likelihood of reported electricity outages and their duration being materially misstated in the Disclosure Information, we have no matters to report.</td></tr>
<tr><td>Valuation of related-party transactions at arm’s-length

The Determination and the IM Determination place a requirement on the Company to value related-party transactions at arm’s-length. In other words, the value at which a transaction, with the same terms and conditions, would be entered into between a willing seller and a willing buyer who are unrelated and who are acting independently of each other and pursuing their own best interests.

In the absence of an active market for related-party transactions, assignment of an objective arm’s-length value to a related-party transaction is difficult.

This a key 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.</td><td>We have obtained an understanding of the Company’s approach to identifying and valuing related-party transactions at arm’s-length in accordance with the Determination and the IM Determination.

The procedures we carried out, to satisfy ourselves that related-party transactions are appropriately valued at a value not greater than arm’s-length, included:

• testing the completeness of related-parties identified through review of Board minutes, review of Companies Office records, and related-parties identified through detailed testing of transactions and balances in the annual financial statements audit;

• reviewing the relevant policies for approval and negotiation of related-party transactions, and testing compliance with them;

• reviewing the advice received by the Company from the Commerce Commission on the reasonableness of the approach adopted to determine arm’s-length value for related-party transactions with its associates and joint venture;

• confirming the Company followed the advice it received from the Commerce Commission on the reasonableness of the approach adopted to report sales of goods and services to its associates and joint venture; and

• confirming the material accuracy of related party values disclosed, and compliance of their calculation with the Determination and the IM Determination.</td></tr>
</table>

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
27 August 2021