COMMERCE COMMISSION NEW ZEALAND

EDB Information Disclosure Requirements
Information Templates
for
Schedules 1–10

Company Name	Network Tasman Limited
Disclosure Date	31 August 2019
Disclosure Year (year ended)	31 March 2019

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 2019**

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**	16,538	263	93,833	2,907	24,791
10	Network	9,432	150	53,518	1,658	14,140
11	Non-network	7,105	113	40,315	1,249	10,652
12						
13	**Expenditure on assets**	15,828	252	89,804	2,782	23,727
14	Network	14,442	229	81,943	2,538	21,650
15	Non-network	1,386	22	7,861	244	2,077
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**	56,646	900
20	Standard consumer line charge revenue	61,262	795
21	Non-standard consumer line charge revenue	36,119	1,403,667
22			

23 **1(iii): Service intensity measures**

sch ref			
24			
25	Demand density	37	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
26	Volume density	176	*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	15,891	*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	10,504	29.25%
33	Pass-through and recoverable costs excluding financial incentives and wash-ups	12,843	35.77%
34	Total depreciation	6,807	18.96%
35	Total revaluations	2,452	6.83%
36	Regulatory tax allowance	1,844	5.13%
37	Regulatory profit/(loss) including financial incentives and wash-ups	6,361	17.71%
38	**Total regulatory income**	35,906	
39			

40 **1(v): Reliability**

sch ref			
41			
42	Interruption rate	7.36	*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).

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sch ref

2(i): Return on Investment

	CY-2	CY-1	Current Year CY
	31 Mar 17	31 Mar 18	31 Mar 19
ROI – comparable to a post tax WACC	%	%	%
Reflecting all revenue earned	9.59%	8.70%	3.35%
Excluding revenue earned from financial incentives	7.61%	6.75%	1.42%
Excluding revenue earned from financial incentives and wash-ups	7.73%	6.88%	1.55%
Mid-point estimate of post tax WACC	4.77%	5.04%	4.75%
25th percentile estimate	4.05%	4.36%	4.07%
75th percentile estimate	5.48%	5.72%	5.43%
ROI – comparable to a vanilla WACC			
Reflecting all revenue earned	10.14%	9.29%	3.86%
Excluding revenue earned from financial incentives	8.15%	7.35%	1.93%
Excluding revenue earned from financial incentives and wash-ups	8.27%	7.47%	2.06%
WACC rate used to set regulatory price path	7.19%	7.19%	7.19%
Mid-point estimate of vanilla WACC	5.31%	5.60%	5.26%
25th percentile estimate	4.59%	4.92%	4.58%
75th percentile estimate	6.03%	6.29%	5.94%

2(ii): Information Supporting the ROI

			($000)	
	Total opening RAB value	165,522		
plus	Opening deferred tax	(1,612)		
Opening RIV			163,910	
Line charge revenue			35,979	
	Expenses cash outflow	23,347		
add	Assets commissioned	6,557		
less	Asset disposals	393		
add	Tax payments	1,438		
less	Other regulated income	(73)		
Mid-year net cash outflows			31,022	
Term credit spread differential allowance			–	
	Total closing RAB value	165,472		
less	Adjustment resulting from asset allocation	(1,859)		
less	Lost and found assets adjustment	–		
plus	Closing deferred tax	(2,018)		
Closing RIV			165,313	
ROI – comparable to a vanilla WACC				3.86%
	Leverage (%)			42%
	Cost of debt assumption (%)			4.33%
	Corporate tax rate (%)			28%
ROI – comparable to a post tax WACC				3.35%

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2019**

SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

This schedule requires information on the Return on Investment (ROI) for the EDB relative to the Commerce Commission's estimates of post tax WACC and vanilla WACC. EDBs must calculate their ROI based on a monthly basis if required by clause 2.3.3 of the ID Determination or if they elect to. If an EDB makes this election, information supporting this calculation must be provided in 2(iii).
EDBs must provide explanatory comment on their ROI in Schedule 14 (Mandatory Explanatory Notes).
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sch ref							
61	**2(iii): Information Supporting the Monthly ROI**						
62							
63	**Opening RIV**						N/A
64							
65							
66		**Line charge revenue**	**Expenses cash outflow**	**Assets commissioned**	**Asset disposals**	**Other regulated income**	**Monthly net cash outflows**
67	April						–
68	May						–
69	June						–
70	July						–
71	August						–
72	September						–
73	October						–
74	November						–
75	December						–
76	January						–
77	February						–
78	March						–
79	**Total**	–	–	–	–	–	–
80							
81	**Tax payments**						N/A
82							
83	**Term credit spread differential allowance**						N/A
84							
85	**Closing RIV**						N/A
86							
87							
88	**Monthly ROI – comparable to a vanilla WACC**						N/A
89							
90	**Monthly ROI – comparable to a post tax WACC**						N/A
91							
92	**2(iv): Year-End ROI Rates for Comparison Purposes**						
93							
94	**Year-end ROI – comparable to a vanilla WACC**						1.36%
95							
96	**Year-end ROI – comparable to a post tax WACC**						0.85%
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							
102	Net recoverable costs allowed under incremental rolling incentive scheme					–	
103	Purchased assets – avoided transmission charge					4,378	
104	Energy efficiency and demand incentive allowance						
105	Quality incentive adjustment					–	
106	Other financial incentives					–	
107	**Financial incentives**						4,378
108							
109	**Impact of financial incentives on ROI**						1.93%
110							
111	Input methodology claw-back					–	
112	CPP application recoverable costs					–	
113	Catastrophic event allowance					–	
114	Capex wash-up adjustment					(288)	
115	Transmission asset wash-up adjustment					–	
116	2013–15 NPV wash-up allowance					–	
117	Reconsideration event allowance					–	
118	Other wash-ups					–	
119	**Wash-up costs**						(288)
120							
121	**Impact of wash-up costs on ROI**						–0.13%

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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		35,979
10	*plus*	Gains / (losses) on asset disposals		(208)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)		135
12				
13		**Total regulatory income**		35,906
14		**Expenses**		
15	*less*	Operational expenditure		10,504
16				
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups		12,843
18				
19		**Operating surplus / (deficit)**		12,559
20				
21	*less*	Total depreciation		6,807
22				
23	*plus*	Total revaluations		2,452
24				
25		**Regulatory profit / (loss) before tax**		8,204
26				
27	*less*	Term credit spread differential allowance		–
28				
29	*less*	Regulatory tax allowance		1,844
30				
31		**Regulatory profit/(loss) including financial incentives and wash-ups**		6,361
32				
33	**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**		**($000)**	
34		**Pass through costs**		
35		Rates	176	
36		Commerce Act levies	82	
37		Industry levies	141	
38		CPP specified pass through costs	–	
39		**Recoverable costs excluding financial incentives and wash-ups**		
40		Electricity lines service charge payable to Transpower	10,391	
41		Transpower new investment contract charges	127	
42		System operator services	–	
43		Distributed generation allowance	1,926	
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**		12,843
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 18**	**31 Mar 19**
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 14	–	–
58	CY-4	31 Mar 15	–	–
59	CY-3	31 Mar 16	–	–
60	CY-2	31 Mar 17	–	–
61	CY-1	31 Mar 18	–	–
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

sch ref	4(i): Regulatory Asset Base Value (Rolled Forward)		RAB	RAB	RAB	RAB	RAB
8		for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**
9			**($000)**	**($000)**	**($000)**	**($000)**	**($000)**
10		**Total opening RAB value**	155,232	161,816	163,098	164,637	165,522
11							
12	*less*	**Total depreciation**	6,778	6,937	6,779	6,954	6,807
13							
14	*plus*	**Total revaluations**	130	948	3,531	1,808	2,452
15							
16	*plus*	**Assets commissioned**	13,773	7,777	5,612	6,386	6,557
17							
18	*less*	**Asset disposals**	541	506	825	355	393
19							
20	*plus*	**Lost and found assets adjustment**	–	–	–	–	–
21							
22	*plus*	**Adjustment resulting from asset allocation**	(0)	0	–	–	(1,859)
23							
24		**Total closing RAB value**	161,816	163,098	164,637	165,522	165,472
25							

sch ref	4(ii): Unallocated Regulatory Asset Base		Unallocated RAB *		RAB	
28			**($000)**	**($000)**	**($000)**	**($000)**
29		**Total opening RAB value**		165,521		165,522
30	*less*					
31		**Total depreciation**		6,953		6,807
32	*plus*					
33		**Total revaluations**		2,452		2,452
34	*plus*					
35		Assets commissioned (other than below)	6,674		6,557	
36		Assets acquired from a regulated supplier	–		–	
37		Assets acquired from a related party	–		–	
38		**Assets commissioned**		6,674		6,557
39	*less*					
40		Asset disposals (other than below)	409		393	
41		Asset disposals to a regulated supplier	–		–	
42		Asset disposals to a related party	–		–	
43		**Asset disposals**		409		393
44						
45	*plus*	**Lost and found assets adjustment**		–		–
46						
47	*plus*	**Adjustment resulting from asset allocation**				(1,859)
48						
49		**Total closing RAB value**		167,285		165,472

** 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				1,026
55		CPI_4^{-4}				1,011
56		Revaluation rate (%)				1.48%
57						
58			**Unallocated RAB ***		**RAB**	
59			**($000)**	**($000)**	**($000)**	**($000)**
60		Total opening RAB value	165,521		165,522	
61	*less*	Opening value of fully depreciated, disposed and lost assets	233		230	
62						
63		Total opening RAB value subject to revaluation	165,288		165,292	
64		**Total revaluations**		2,452		2,452
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**		2,263		2,263
69	*plus*	Capital expenditure	10,142		10,142	
70	*less*	Assets commissioned	6,674		6,557	
71	*plus*	Adjustment resulting from asset allocation			(119)	
72		**Works under construction - current disclosure year**		5,731		5,729
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)

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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	6,680		6,587	
80	Depreciation - no standard life assets	273		220	
81	Depreciation - modified life assets	–		–	
82	Depreciation - alternative depreciation in accordance with CPP	–		–	
83	**Total depreciation**		6,953		6,807
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**	7,954	9,440	23,067	24,310	52,686	23,458	7,739	13,441	3,427	165,522
100	*less*	Total depreciation	281	197	812	1,824	1,456	1,049	346	627	215	6,807
101	*plus*	Total revaluations	118	139	348	362	781	340	116	198	50	2,452
102	*plus*	Assets commissioned	130	–	92	1,942	882	1,734	755	324	698	6,557
103	*less*	Asset disposals	–	–	–	55	105	159	7	18	49	393
104	*plus*	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
105	*plus*	Adjustment resulting from asset allocation	–	–	–	(73)	–	–	–	(1,090)	(696)	(1,859)
106	*plus*	Asset category transfers	–	(47)	475	75	45	(518)	44	(74)	–	–
107		**Total closing RAB value**	7,921	9,335	23,170	24,737	52,833	23,806	8,301	12,154	3,215	165,472
108												
109		**Asset Life**										
110		Weighted average remaining asset life	37.7	47.8	28.4	32.9	44.6	32.4	31.1	17.2	23.2	(years)
111		Weighted average expected total asset life	58.4	56.3	40.4	58.8	60.4	51.1	41.9	33.7	30.0	(years)

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SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

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

sch ref					
7	**5a(i): Regulatory Tax Allowance**			**($000)**	
8		**Regulatory profit / (loss) before tax**		8,204	
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	(5)		*
12		Amortisation of initial differences in asset values	3,239		
13		Amortisation of revaluations	517		
14				3,751	
15					
16	*less*	Total revaluations	2,452		
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	2,918		
21				5,371	
22					
23		**Regulatory taxable income**		6,585	
24					
25	*less*	Utilised tax losses	–		
26		Regulatory net taxable income		6,585	
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**		1,844	
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	82,141		
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	7		
40		Closing unamortised initial differences in asset values		78,895	
41					
42		Opening weighted average remaining useful life of relevant assets (years)		25	
43					

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SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

This schedule requires information on the calculation of the regulatory tax allowance. This information is used to calculate regulatory profit/loss in Schedule 3 (regulatory profit). EDBs must provide explanatory commentary on the information disclosed in this schedule, in Schedule 14 (Mandatory Explanatory Notes).
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sch ref				
44		**5a(iv): Amortisation of Revaluations**		**($000)**
45				
46		Opening sum of RAB values without revaluations	150,203	
47				
48		Adjusted depreciation	6,290	
49		Total depreciation	6,807	
50		Amortisation of revaluations		517
51				
52		**5a(v): Reconciliation of Tax Losses**		**($000)**
53				
54		**Opening tax losses**	–	
55	*plus*	Current period tax losses	–	
56	*less*	Utilised tax losses	–	
57		**Closing tax losses**		–
58		**5a(vi): Calculation of Deferred Tax Balance**		**($000)**
59				
60		**Opening deferred tax**	(1,612)	
61				
62	*plus*	Tax effect of adjusted depreciation	1,761	
63				
64	*less*	Tax effect of tax depreciation	1,432	
65				
66	*plus*	Tax effect of other temporary differences*	40	
67				
68	*less*	Tax effect of amortisation of initial differences in asset values	907	
69				
70	*plus*	Deferred tax balance relating to assets acquired in the disclosure year	–	
71				
72	*less*	Deferred tax balance relating to assets disposed in the disclosure year	(78)	
73				
74	*plus*	Deferred tax cost allocation adjustment	54	
75				
76		**Closing deferred tax**		(2,018)
77				
78		**5a(vii): Disclosure of Temporary Differences**		
79		*In Schedule 14, Box 6, provide descriptions and workings of items recorded in the asterisked category in Schedule 5a(vi) (Tax effect of other temporary differences).*		
80				
81		**5a(viii): Regulatory Tax Asset Base Roll-Forward**		
82				**($000)**
83		**Opening sum of regulatory tax asset values**	63,134	
84	*less*	Tax depreciation	5,114	
85	*plus*	Regulatory tax asset value of assets commissioned	6,639	
86	*less*	Regulatory tax asset value of asset disposals	114	
87	*plus*	Lost and found assets adjustment	–	
88	*plus*	Adjustment resulting from asset allocation	(1,666)	
89	*plus*	Other adjustments to the RAB tax value	–	
90		**Closing sum of regulatory tax asset values**		62,879

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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**		69
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**
For Year Ended **31 March 2019**

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 2019**

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						
7	**5d(i): Operating Cost Allocations**					
8			**Value allocated ($000s)**			
9		**Arm's length deduction**	**Electricity distribution services**	**Non-electricity distribution services**	**Total**	**OVABAA allocation increase ($000s)**
10	**Service interruptions and emergencies**					
11	Directly attributable		909			
12	Not directly attributable	–	–	–	–	–
13	**Total attributable to regulated service**		909			
14	**Vegetation management**					
15	Directly attributable		1,078			
16	Not directly attributable	–	–	–	–	–
17	**Total attributable to regulated service**		1,078			
18	**Routine and corrective maintenance and inspection**					
19	Directly attributable		2,133			
20	Not directly attributable	–	–	–	–	–
21	**Total attributable to regulated service**		2,133			
22	**Asset replacement and renewal**					
23	Directly attributable		1,871			
24	Not directly attributable	–	–	–	–	–
25	**Total attributable to regulated service**		1,871			
26	**System operations and network support**					
27	Directly attributable		2,157			
28	Not directly attributable	–	–	–	–	–
29	**Total attributable to regulated service**		2,157			
30	**Business support**					
31	Directly attributable		532			
32	Not directly attributable	–	1,824	927	2,751	–
33	**Total attributable to regulated service**		2,356			
34						
35	**Operating costs directly attributable**		8,680			
36	**Operating costs not directly attributable**	–	1,824	927	2,751	–
37	**Operational expenditure**		10,504			
38						

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2019**

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	398
43	Not directly attributable	2
44	**Total attributable to regulated service**	400
45	**Recoverable costs**	
46	Directly attributable	12,444
47	Not directly attributable	–
48	**Total attributable to regulated service**	12,444
49		

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

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

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

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2019**

SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

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

sch ref

7 5e(i): Regulated Service Asset Values

sch ref		Value allocated ($000s) Electricity distribution services
10	**Subtransmission lines**	
11	Directly attributable	7,921
12	Not directly attributable	–
13	**Total attributable to regulated service**	7,921
14	**Subtransmission cables**	
15	Directly attributable	9,335
16	Not directly attributable	–
17	**Total attributable to regulated service**	9,335
18	**Zone substations**	
19	Directly attributable	23,170
20	Not directly attributable	–
21	**Total attributable to regulated service**	23,170
22	**Distribution and LV lines**	
23	Directly attributable	23,510
24	Not directly attributable	1,227
25	**Total attributable to regulated service**	24,737
26	**Distribution and LV cables**	
27	Directly attributable	52,833
28	Not directly attributable	–
29	**Total attributable to regulated service**	52,833
30	**Distribution substations and transformers**	
31	Directly attributable	23,806
32	Not directly attributable	–
33	**Total attributable to regulated service**	23,806
34	**Distribution switchgear**	
35	Directly attributable	8,301
36	Not directly attributable	–
37	**Total attributable to regulated service**	8,301
38	**Other network assets**	
39	Directly attributable	12,112
40	Not directly attributable	41
41	**Total attributable to regulated service**	12,153
42	**Non-network assets**	
43	Directly attributable	968
44	Not directly attributable	2,248
45	**Total attributable to regulated service**	3,216
46		
47	**Regulated service asset value directly attributable**	161,956
48	**Regulated service asset value not directly attributable**	3,516
49	**Total closing RAB value**	165,472

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

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

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

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

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

80 *† include additional rows if needed*

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2019**

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		1,013
9		System growth		4,149
10		Asset replacement and renewal		2,392
11		Asset relocations		678
12		Reliability, safety and environment:		
13		Quality of supply	444	
14		Legislative and regulatory	410	
15		Other reliability, safety and environment	87	
16		**Total reliability, safety and environment**		941
17		**Expenditure on network assets**		9,173
18		Expenditure on non-network assets		880
19				
20		**Expenditure on assets**		10,053
21	*plus*	Cost of financing		–
22	*less*	Value of capital contributions		136
23	*plus*	Value of vested assets		225
24				
25		**Capital expenditure**		10,142
26		**6a(ii): Subcomponents of Expenditure on Assets (where known)**		**($000)**
27		Energy efficiency and demand side management, reduction of energy losses		–
28		Overhead to underground conversion		659
29		Research and development		–
30		**6a(iii): Consumer Connection**		
31		*Consumer types defined by EDB**	**($000)**	**($000)**
32		Consumers 20kVA and less	379	
33		Consumers greater than 20kVA	634	
34		–	–	
35		–	–	
36		–	–	
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		1,013
39				
40	*less*	Capital contributions funding consumer connection expenditure	2	
41		**Consumer connection less capital contributions**		1,011
42		**6a(iv): System Growth and Asset Replacement and Renewal**		**Asset Replacement and**
43			**System Growth**	**Renewal**
44			**($000)**	**($000)**
45		Subtransmission	41	190
46		Zone substations	45	1,770
47		Distribution and LV lines	804	49
48		Distribution and LV cables	309	119
49		Distribution substations and transformers	516	99
50		Distribution switchgear	3	129
51		Other network assets	2,431	36
52		**System growth and asset replacement and renewal expenditure**	4,149	2,392
53	*less*	Capital contributions funding system growth and asset replacement and renewal	–	118
54		**System growth and asset replacement and renewal less capital contributions**	4,149	2,274
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	678	
65		**Asset relocations expenditure**		678
66	*less*	Capital contributions funding asset relocations	16	
67		**Asset relocations less capital contributions**		662

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2019**

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		444	
78		**Quality of supply expenditure**			444
79	*less*	Capital contributions funding quality of supply		–	
80		**Quality of supply less capital contributions**			444
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		410	
90		**Legislative and regulatory expenditure**			410
91	*less*	Capital contributions funding legislative and regulatory		–	
92		**Legislative and regulatory less capital contributions**			410
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		87	
102		**Other reliability, safety and environment expenditure**			87
103	*less*	Capital contributions funding other reliability, safety and environment		–	
104		**Other reliability, safety and environment less capital contributions**			87
105					
106	**6a(ix): Non-Network Assets**				
107	**Routine expenditure**				
108		*Project or programme**		**($000)**	**($000)**
109		Land & Buildings		345	
110		IT		409	
111			–	–	
112			–	–	
113			–	–	
114		** include additional rows if needed*			
115		All other projects or programmes - routine expenditure		126	
116		**Routine expenditure**			880
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**			880

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For Year Ended	**31 March 2019**

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

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

sch ref			
7	**6b(i): Operational Expenditure**	**($000)**	**($000)**
8	Service interruptions and emergencies	909	
9	Vegetation management	1,078	
10	Routine and corrective maintenance and inspection	2,133	
11	Asset replacement and renewal	1,871	
12	**Network opex**		5,991
13	System operations and network support	2,157	
14	Business support	2,356	
15	**Non-network opex**		4,513
16			
17	**Operational expenditure**		10,504
18	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
19	Energy efficiency and demand side management, reduction of energy losses		130
20	Direct billing*		–
21	Research and development		–
22	Insurance		308
23	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2019**

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	35,250	35,979	2%
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	520	1,013	95%
11	System growth	7,857	4,149	(47%)
12	Asset replacement and renewal	2,249	2,392	6%
13	Asset relocations	820	678	(17%)
14	Reliability, safety and environment:			
15	Quality of supply	898	444	(51%)
16	Legislative and regulatory	420	410	(2%)
17	Other reliability, safety and environment	330	87	(74%)
18	**Total reliability, safety and environment**	1,648	941	(43%)
19	**Expenditure on network assets**	13,094	9,173	(30%)
20	Expenditure on non-network assets	438	880	101%
21	Expenditure on assets	13,532	10,053	(26%)
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	1,305	909	(30%)
24	Vegetation management	1,006	1,078	7%
25	Routine and corrective maintenance and inspection	1,798	2,133	19%
26	Asset replacement and renewal	2,083	1,871	(10%)
27	**Network opex**	6,192	5,991	(3%)
28	System operations and network support	2,024	2,157	7%
29	Business support	2,502	2,356	(6%)
30	**Non-network opex**	4,526	4,513	(0%)
31	**Operational expenditure**	10,718	10,504	(2%)
32	**7(iv): Subcomponents of Expenditure on Assets (where known)**			
33	Energy efficiency and demand side management, reduction of energy losses	–	–	–
34	Overhead to underground conversion	820	659	(20%)
35	Research and development	–	–	–
36				
37	**7(v): Subcomponents of Operational Expenditure (where known)**			
38	Energy efficiency and demand side management, reduction of energy losses	32	130	306%
39	Direct billing	–	–	–
40	Research and development	–	–	–
41	Insurance	275	308	12%
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 2019**
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							
				Price component	0STL	0UNM	1ANY	1DAY	1NIT	1WSR	2ANY	2DAY
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)	W/day	day	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh
0S	Streetlamps	Standard	–	2,077	479,452	–	–	–	–	–	–	–
0UNM	Unmetered Supplies	Standard	–	14	–	76	–	–	–	–	–	–
1	15 kVA Capacity	Standard	37,006	254,581	7,085	–	186,735	2,444	4,353	61,049	–	–
2	Capacity	Standard	2,746	100,848	7,085	–	–	–	–	–	70,540	18,489
2HLFC	20 or 30 kVA	Standard	4	28	–	–	–	–	–	–	–	–
2LLFC	40-150kVA Capacity	Standard	41	286	–	–	–	–	–	–	–	–
HLF	150kVA Capacity	Standard	1	10,039	–	–	–	–	–	–	–	–
3.1	3000kVA	Standard	4	9,948	–	–	–	–	–	–	–	–
3.3	3000kVA	Standard	5	9,172	–	–	–	–	–	–	–	–
3.4	3000kVA	Standard	160	116,511	–	–	–	–	–	–	–	–
3.5	3000kVA	Standard	2	15,056	–	–	–	–	–	–	–	–
6.1	> 3000,	Non-standard	1	103,311	–	–	–	–	–	–	–	–
6.2	> 3000,	Non-standard	1	13,271	–	–	–	–	–	–	–	–
CB	Cobb River Hydro	Non-standard	1	5	–	–	–	–	–	–	–	–
MAT	-	[Select one]	–	–	–	–	–	–	–	–	–	–
Connections	-	[Select one]	–	–	–	–	–	–	–	–	–	–
Solar Connections	-	[Select one]	–	–	–	–	–	–	–	–	–	–
-	-	[Select one]	–	–	–	–	–	–	–	–	–	–
Add extra rows for additional consumer groups or price category codes as necessary												
		Standard consumer totals	39,967	518,560	493,622	76	186,735	2,444	4,353	61,049	70,540	18,489
		Non-standard consumer totals	3	116,587	–	–	–	–	–	–	–	–
		Total for all consumers	39,970	635,147	493,622	76	186,735	2,444	4,353	61,049	70,540	18,489

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

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)	2NIT	2WSR	2HANY	2HDAY	2HNIT	2HWSR	2LANY	2LDAY	2LNIT	2LWSR	HLFANY	HLFDAY	HLFNIT	HLFWSR
			c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh
0S	Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
1	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
2	Capacity	Standard	8,295	3,524	–	–	–	–	–	–	–	–	–	–	–	–
2HLFC	20 or 30 kVA	Standard	–	–	17	–	2	9	–	–	–	–	–	–	–	–
2LLFC	40-150kVA Capacity	Standard	–	–	–	–	–	–	215	20	12	39	–	–	–	–
HLF	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	4,566	3,949	1,494	30
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	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Connections	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Solar Connections	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–
-	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Add extra rows for additional consumer groups or price category c																
		Standard consumer totals	8,295	3,524	17	–	2	9	215	20	12	39	4,566	3,949	1,494	30
		Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–	–	–	–	–
		Total for all consumers	8,295	3,524	17	–	2	9	215	20	12	39	4,566	3,949	1,494	30

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

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)	GENA	1	2	2HLFC	2LLFC	HLF	AnyDem31	AnyDem33	AnyDem34	AnyDem35	WinDem	kVAr	SD31	SN31
			c/kWh	Daily	kVA per Day	Daily	Daily	kVA per Day	kVA / day	kVA / day	kVA / day	kVA / day	kW / day	kVAr / day	c/kWh	c/kWh
0S	Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
1	15 kVA Capacity	Standard	–	36,749	–	–	–	–	–	–	–	–	–	–	–	–
2	Capacity	Standard	–	–	126,091	–	–	–	–	–	–	–	–	–	–	–
2HLFC	20 or 30 kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
2LLFC	40-150kVA Capacity	Standard	–	–	–	–	37	–	–	–	–	–	–	–	–	–
HLF	150kVA Capacity	Standard	–	–	–	–	–	3,276	–	–	–	–	–	–	–	–
3.1	3000kVA	Standard	–	–	–	–	–	–	2,233	–	–	–	1,518	–	4,198	1,723
3.3	3000kVA	Standard	–	–	–	–	–	–	–	2,310	–	–	934	–	–	–
3.4	3000kVA	Standard	–	–	–	–	–	–	–	–	45,182	–	17,990	189	–	–
3.5	3000kVA	Standard	–	–	–	–	–	–	–	–	–	3,703	1,685	–	–	–
6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
CB	Cobb River Hydro	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
MAT	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Connections	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Solar Connections	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–
-	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Add extra rows for additional consumer groups or price category c																
		Standard consumer totals	–	36,749	126,091	–	37	3,276	2,233	2,310	45,182	3,703	22,127	189	4,198	1,723
		Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–	–	–	–	–
		Total for all consumers	–	36,749	126,091	–	37	3,276	2,233	2,310	45,182	3,703	22,127	189	4,198	1,723

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

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)	WD31	WN31	SD33	SN33	WD33	WN33	SD34	SN34	WD34	WN34	SD35	SN35	WD35	WN35
12–13				c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh
15	0S	Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
16	0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
17	1	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
18	2	Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
19	2HLFC	20 or 30 kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
20	2LLFC	40-150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
21	HLF	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
22	3.1	3000kVA	Standard	2,818	1,209	–	–	–	–	–	–	–	–	–	–	–	–
23	3.3	3000kVA	Standard	–	–	4,112	1,834	2,306	920	–	–	–	–	–	–	–	–
24	3.4	3000kVA	Standard	–	–	–	–	–	–	48,718	17,352	36,948	13,493	–	–	–	–
25	3.5	3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	5,430	2,454	4,959	2,213
26	6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
27	6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
28	CB	Cobb River Hydro	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
29	MAT	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–
30	Connections	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–
31	Solar Connections	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–
32	-	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–
33	*Add extra rows for additional consumer groups or price category c*																
34			**Standard consumer totals**	2,818	1,209	4,112	1,834	2,306	920	48,718	17,352	36,948	13,493	5,430	2,454	4,959	2,213
35			**Non-standard consumer totals**	–	–	–	–	–	–	–	–	–	–	–	–	–	–
36			**Total for all consumers**	2,818	1,209	4,112	1,834	2,306	920	48,718	17,352	36,948	13,493	5,430	2,454	4,959	2,213

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

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)	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
13				Annual	Annual	kVA=km	New connection application	New connection application	New connection application	New connection application	Annual	Annual	Per application	Per application	Per application	Per application
15	0S	Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
16	0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
17	1	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
18	2	Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
19	2HLFC	20 or 30 kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
20	2LLFC	40-150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
21	HLF	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
22	3.1	3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
23	3.3	3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	3.4	3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
25	3.5	3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
26	6.1	> 3000,	Non-standard	1,986	528	–	–	–	–	–	–	–	–	–	–	–
27	6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
28	CB	Cobb River Hydro	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
29	MAT	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–
30	Connections	-	[Select one]	–	–	40,055	–	–	–	–	–	–	–	–	–	–
31	Solar Connections	-	[Select one]	–	–	–	–	591	52	14	–	–	229	1	15	2
32	-	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–
33	*Add extra rows for additional consumer groups or price category c*															
34			**Standard consumer totals**	–	–	–	–	–	–	–	–	–	–	–	–	–
35			**Non-standard consumer totals**	1,986	528	–	–	–	–	–	–	–	–	–	–	–
36			**Total for all consumers**	1,986	528	–	–	–	–	–	–	–	–	–	–	–

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2019**
Network / Sub-Network Name	**Network Tasman Limited**

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

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

								Line charge revenues ($000) by price component							
							Price component	0STL	0UNM	1ANY	1DAY	1NIT	1WSR	2ANY	2DAY
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)	Rate (eg, $ per day, $ per kWh, etc.)	0.00119	0.54	0.0674	0.0768	0.0051	0.0171	0.056	0.0644
0S	Streetlamps	Standard	$203	–	$138	$65		$203	–	–	–	–	–	–	–
0UNM	Unmetered Supplies	Standard	$15	–	$10	$5		–	$15	–	–	–	–	–	–
1	15 kVA Capacity	Standard	$15,891	$6,582	$8,929	$6,962		$3	–	$12,633	$188	$20	$1,035	–	–
2	Capacity	Standard	$7,584	$2,620	$4,809	$2,775		$3	–	–	–	–	–	$3,952	$1,193
2HLFC	20 or 30 kVA	Standard	$4	$1	$3	$1		–	–	–	–	–	–	–	–
2LLFC	40-150kVA Capacity	Standard	$28	$7	$19	$9		–	–	–	–	–	–	–	–
HLF	150kVA Capacity	Standard	$517	$184	$359	$158		–	–	–	–	–	–	–	–
3.1	3000kVA	Standard	$304	$30	$113	$191		–	–	–	–	–	–	–	–
3.3	3000kVA	Standard	$322	$78	$192	$130		–	–	–	–	–	–	–	–
3.4	3000kVA	Standard	$5,865	$1,174	$3,365	$2,500		–	–	–	–	–	–	–	–
3.5	3000kVA	Standard	$523	$114	$295	$228		–	–	–	–	–	–	–	–
6.1	> 3000,	Non-standard	$1,986	$27	$194	$1,792		–	–	–	–	–	–	–	–
6.2	> 3000,	Non-standard	$528	$39	$197	$331		–	–	–	–	–	–	–	–
Connections	-	Standard	$512	–	$512	–		–	–	–	–	–	–	–	–
generators	MAT, CB, EG etc	Non-standard	$1,697	–	$1,354	$343		–	–	–	–	–	–	–	–
-	-	[Select one]	–	–	–	–		–	–	–	–	–	–	–	–
-	-	[Select one]	–	–	–	–		–	–	–	–	–	–	–	–
Add extra rows for additional consumer groups or price category codes as necessary															
		Standard consumer totals	$31,768	$10,790	$18,744	$13,024		$209	$15	$12,633	$188	$20	$1,035	$3,952	$1,193
		Non-standard consumer totals	$4,211	$66	$1,745	$2,466		–	–	–	–	–	–	–	–
		Total for all consumers	$35,979	$10,856	$20,489	$15,490	–	$209	$15	$12,633	$188	$20	$1,035	$3,952	$1,193

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8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	5

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

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

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	2NIT	2WSR	2HANY	2HDAY	2HNIT	2HWSR	2LANY	2LDAY	2LNIT	2LWSR	HLFANY	HLFDAY	HLFNIT	HLFWSR
			0.0012	0.0119	0.1459	0.1543	0.0907	0.1016	0.0976	0.106	0.0425	0.0533	0.0159	0.0179	0	0.0032
0S	Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
1	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
2	Capacity	Standard	$10	$42	–	–	–	–	–	–	–	–	–	–	–	–
2HLFC	20 or 30 kVA	Standard	–	–	$3	–	–	$1	–	–	–	–	–	–	–	–
2LLFC	40-150kVA Capacity	Standard	–	–	–	–	–	–	$21	$2	$1	$2	–	–	–	–
HLF	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	$73	$71	–	–
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	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Connections	-	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
generators	MAT, CB, EG etc	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
-	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–
-	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Add extra rows for additional consumer groups or price category c																
		Standard consumer totals	$10	$42	$3	–	–	$1	$21	$2	$1	$2	$73	$71	–	–
		Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–	–	–	–	–
		Total for all consumers	$10	$42	$3	–	–	$1	$21	$2	$1	$2	$73	$71	–	–

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	5

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

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

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	GENA	1	2	2HLFC	2LLFC	HLF	AnyDem31	AnyDem33	AnyDem34	AnyDem35	WinDem	kVAr	SD31	SN31
			0	0.15	0.0531	0.15	0.15	0.3119	0.1141	0.1376	0.1445	0.1376	0.3285	0.261	0.0027	0.0014
0S	Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
1	15 kVA Capacity	Standard	–	$2,012	–	–	–	–	–	–	–	–	–	–	–	–
2	Capacity	Standard	–	–	$2,384	–	–	–	–	–	–	–	–	–	–	–
2HLFC	20 or 30 kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
2LLFC	40-150kVA Capacity	Standard	–	–	–	–	$2	–	–	–	–	–	–	–	–	–
HLF	150kVA Capacity	Standard	–	–	–	–	–	$373	–	–	–	–	–	–	–	–
3.1	3000kVA	Standard	–	–	–	–	–	–	$93	–	–	–	$182	–	$11	$2
3.3	3000kVA	Standard	–	–	–	–	–	–	–	$116	–	–	$112	–	–	–
3.4	3000kVA	Standard	–	–	–	–	–	–	–	–	$2,383	–	$2,157	$18	–	–
3.5	3000kVA	Standard	–	–	–	–	–	–	–	–	–	$186	$202	–	–	–
6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Connections	-	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
generators	MAT, CB, EG etc	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
-	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–
-	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Add extra rows for additional consumer groups or price category c																
		Standard consumer totals	–	$2,012	$2,384	–	$2	$373	$93	$116	$2,383	$186	$2,653	$18	$11	$2
		Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–	–	–	–	–
		Total for all consumers	–	$2,012	$2,384	–	$2	$373	$93	$116	$2,383	$186	$2,653	$18	$11	$2

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	5

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

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

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	WD31	WN31	SD33	SN33	WD33	WN33	SD34	SN34	WD34	WN34	SD35	SN35	WD35	WN35
			0.0049	0.0014	0.0082	0.0043	0.021	0.0043	0.0082	0.0043	0.021	0.0043	0.0056	0.0034	0.0179	0.0034
0S	Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
1	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
2	Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
2HLFC	20 or 30 kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
2LLFC	40-150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
HLF	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
3.1	3000kVA	Standard	$14	$2	–	–	–	–	–	–	–	–	–	–	–	–
3.3	3000kVA	Standard	–	–	$34	$8	$48	$4	–	–	–	–	–	–	–	–
3.4	3000kVA	Standard	–	–	–	–	–	–	$399	$75	$775	$58	–	–	–	–
3.5	3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	$30	$8	$89	$8
6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Connections	-	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
generators	MAT, CB, EG etc	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–
-	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–
-	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Add extra rows for additional consumer groups or price category c																
		Standard consumer totals	$14	$2	$34	$8	$48	$4	$399	$75	$775	$58	$30	$8	$89	$8
		Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–	–	–	–	–
		Total for all consumers	$14	$2	$34	$8	$48	$4	$399	$75	$775	$58	$30	$8	$89	$8

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end 5

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

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

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	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
			Annual	Annual	7.714143004	125	250	325	400	Annual	Annual	100	200	500	1000
0S	Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
1	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
2	Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
2HLFC	20 or 30 kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
2LLFC	40-150kVA 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	$1,986	–	–	–	–	–	–	–	–	–	–	–	–
6.2	> 3000,	Non-standard	–	$528	–	–	–	–	–	–	–	–	–	–	–
Connections	-	Standard	–	–	$309	–	$148	$17	$6	–	–	$23	$0	$8	$2
generators	MAT, CB, EG etc	Non-standard	–	–	–	–	–	–	–	$1,695	$2	–	–	–	–
-	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–
-	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–
Add extra rows for additional consumer groups or price category c															
		Standard consumer totals	–	–	$309	–	$148	$17	$6	–	–	$23	$0	$8	$2
		Non-standard consumer totals	$1,986	$528	–	–	–	–	–	$1,695	$2	–	–	–	–
		Total for all consumers	$1,986	$528	$309	–	$148	$17	$6	$1,695	$2	$23	$0	$8	$2

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	5

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2019**
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

8	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
9	All	Overhead Line	Concrete poles / steel structure	No.	25,987	26,087	100	3
10	All	Overhead Line	Wood poles	No.	1,491	1,575	84	3
11	All	Overhead Line	Other pole types	No.	540	528	(12)	3
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	281	281	–	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	4
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	27	27	–	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	102	–	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	20	–	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	99	95	(4)	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	1,894	1,893	(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	122	130	8	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.	62	70	8	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.	1,279	1,314	35	3
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	186	143	(43)	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	102	117	15	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	3,817	3,803	(14)	3
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	701	734	33	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	502	498	(4)	3
51	LV	LV Cable	LV UG Cable	km	629	646	17	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	–	4
53	LV	Connections	OH/UG consumer service connections	No.	39,861	40,390	529	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	141	110	(31)	4
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	1	1	–	4
56	All	Capacitor Banks	Capacitors including controls	No	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 2019

Number of assets at disclosure year end by installation date

sch ref	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
9																							
10	All	Overhead Line	Concrete poles / steel structure	No.	2,267	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.	59	34	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.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0	–	–
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	117	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	–	2	3	–	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.	–	–	1	4	15	17	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	11	12	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	3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	18	63	164	542	497	836	578	35	74	82	62	67	42	37	22	42	43	41	31
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	4	9	79	122	71	14	17	29	28	28	23	42	26	31	23	18	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	–	24	148	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**
For Year Ended	**31 March 2019**
Network / Sub-network Name	**Network Tasman Limited**

SCHEDULE 9b: ASSET AGE PROFILE

This schedule requires a summary of the age profile (based on year of installation) of the assets that make up the network, by asset cat

sch ref

8		**Disclosure Year (year ended)**	31 March 2019														
9	**Voltage**	**Asset category**	**Asset class**	**Units**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**No. with age unknown**	**Items at end of year (quantity)**	**No. with default dates**	**Data accuracy (1–4)**
10	All	Overhead Line	Concrete poles / steel structure	No.	137	128	150	203	33	130	70	100	466	26,087	–	1
11	All	Overhead Line	Wood poles	No.	15	14	29	–	–	8	42	84	235	1,575	–	1
12	All	Overhead Line	Other pole types	No.	–	1	–	–	–	–	–	–	49	528	–	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	–	–	–	–	–	–	–	27	–	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	–	35	102	–	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.	–	–	–	–	–	–	–	–	–	20	–	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	–	–	1,893	–	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	–	130	–	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	–	70	–	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	849	1,314	–	2
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	4	4	8	9	–	5	2	5	9	143	–	2
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	2	–	–	4	6	15	69	117	–	2
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	40	70	43	23	16	2	2	3	328	3,803	–	3
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	4	18	30	14	13	9	23	33	10	734	–	3
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	498	–	2
52	LV	LV Cable	LV UG Cable	km	9	9	11	12	3	14	13	17	13	646	–	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	29,246	40,390	–	2
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	6	–	–	14	–	–	–	–	110	–	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**
For Year Ended	**31 March 2019**
Network / Sub-network Name	**Network Tasman Limited**

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref

9					
10	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**	
11	> 66kV	–	–	–	
12	50kV & 66kV	158	–	158	
13	33kV	123	30	153	
14	SWER (all SWER voltages)	–	–	–	
15	22kV (other than SWER)	19	13	31	
16	6.6kV to 11kV (inclusive—other than SWER)	1,874	252	2,127	
17	Low voltage (< 1kV)	498	646	1,144	
18	**Total circuit length (for supply)**	2,673	941	3,614	
19					
20	Dedicated street lighting circuit length (km)	–	–	–	
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			18	0
22					

23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**
24	Urban	183	7%
25	Rural	2,294	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**	2,673	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	46%
34		**Circuit length (km)**	**(% of total overhead length)**
35	Overhead circuit requiring vegetation management	2,673	100%

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2019**

SCHEDULE 9d: REPORT ON EMBEDDED NETWORKS

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

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

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

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2019**
Network / Sub-network Name	**Network Tasman Limited**

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref				
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		564	
12	Consumers greater than 20kVA		35	
13	0		–	
14	0		–	
15	0		–	
16	** include additional rows if needed*			
17	**Connections total**		599	
18				
19	**Distributed generation**			
20	Number of connections made in year		185	**connections**
21	Capacity of distributed generation installed in year		0.94	**MVA**
22	**9e(ii): System Demand**			
23				
24				
25	**Maximum coincident system demand**		**Demand at time of maximum coincident demand (MW)**	
26	GXP demand		122	
27	Distributed generation output at HV and above	*plus*	10	
28	**Maximum coincident system demand**		132	
29	Net transfers to (from) other EDBs at HV and above	*less*	20	
30	**Demand on system for supply to consumers' connection points**		112	
31	**Electricity volumes carried**		**Energy (GWh)**	
32	Electricity supplied from GXPs		647	
33	Electricity exports to GXPs	*less*	66	
34	Electricity supplied from distributed generation	*plus*	187	
35	Net electricity supplied to (from) other EDBs	*less*	95	
36	**Electricity entering system for supply to consumers' connection points**		673	
37	Total energy delivered to ICPs	*less*	635	
38	**Electricity losses (loss ratio)**		38	5.7%
39				
40	**Load factor**		0.69	
41	**9e(iii): Transformer Capacity**			
42			**(MVA)**	
43	Distribution transformer capacity (EDB owned)		424	
44	Distribution transformer capacity (Non-EDB owned, estimated)		44	
45	**Total distribution transformer capacity**		468	
46				
47	**Zone substation transformer capacity**		381	

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2019**
Network / Sub-network Name	**Network Tasman Limited**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref			
8	**10(i): Interruptions**		
9	**Interruptions by class**	**Number of interruptions**	
10	Class A (planned interruptions by Transpower)	2	
11	Class B (planned interruptions on the network)	160	
12	Class C (unplanned interruptions on the network)	104	
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**	266	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	70	34
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)	0.05	17.0
26	Class B (planned interruptions on the network)	0.43	134.0
27	Class C (unplanned interruptions on the network)	0.91	105.7
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**	1.39	256.6
35			
36	**Normalised SAIFI and SAIDI**	**Normalised SAIFI**	**Normalised SAIDI**
37	Classes B & C (interruptions on the network)	1.34	230.3
38			

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2019**
Network / Sub-network Name	**Network Tasman Limited**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

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

	Cause	SAIFI	SAIDI
40			
41	**Cause**	**SAIFI**	**SAIDI**
42	Lightning	0.02	1.7
43	Vegetation	0.01	1.1
44	Adverse weather	0.00	0.0
45	Adverse environment	–	–
46	Third party interference	0.38	53.8
47	Wildlife	0.06	4.1
48	Human error	0.01	1.0
49	Defective equipment	0.23	26.4
50	Cause unknown	0.20	17.5
51			

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

	Main equipment involved	SAIFI	SAIDI
53			
54	**Main equipment involved**	**SAIFI**	**SAIDI**
55	Subtransmission lines	0.13	39.3
56	Subtransmission cables	–	–
57	Subtransmission other	–	–
58	Distribution lines (excluding LV)	0.28	89.6
69	Distribution cables (excluding LV)	0.02	4.6
60	Distribution other (excluding LV)	–	–

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

	Main equipment involved	SAIFI	SAIDI
62			
63	**Main equipment involved**	**SAIFI**	**SAIDI**
64	Subtransmission lines	0.20	38.5
65	Subtransmission cables	–	–
66	Subtransmission other	–	–
67	Distribution lines (excluding LV)	0.65	59.2
68	Distribution cables (excluding LV)	0.06	8.0
69	Distribution other (excluding LV)	–	–

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

	Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
71	**Main equipment involved**	**Number of Faults**	**Circuit length (km)**	**Fault rate (faults per 100km)**
72	Subtransmission lines	5	281	1.78
73	Subtransmission cables	–	30	–
74	Subtransmission other	–		
75	Distribution lines (excluding LV)	93	1,893	4.91
76	Distribution cables (excluding LV)	6	265	2.27
77	Distribution other (excluding LV)	–		
78	**Total**	104		

Company Name	Network Tasman Limited
For Year Ended	31 March 2019

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

With the sales discounts changing from a discretionary to a posted discount for the year ending 31 March 2019, they ($10.7m 2019, $10.5m 2018) have now been included in line charge revenue. This is the major component in the change in return on investment from 8.7% in 2018 to 3.35% in 2019.

There have been no other 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 $86,000.

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)

A review was undertaken of the categorisation of the older assets, and the following changes were identified.

Category 2018	*Category 2019*	*$000*	*Explanation*
Distribution & LV Cable	Distribution & LV Lines	227	Line incorrectly categorised as cable
Distribution & LV Lines	Distribution & LV Cable	169	Cable incorrectly categorised as line
Distribution Substations & Transformers	Zone Substations	492	Power transformers incorrectly categorised as distribution
Distribution Substations & Transformers	Distribution Switchgear	95	Switches incorrectly categorised as distribution substations
Distribution Substations & Transformers	Distribution & LV Cable	75	Cable incorrectly categorised as distribution substations
Distribution Switchgear	Distribution & LV Lines	63	Lines incorrectly categorised as switches
Other Network Assets	Distribution Substations & Transformers	88	Distribution substations incorrectly categorised as other network assets
Other small recategorisation		217	
		1,426	

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 (legal and consultancy fees)
- Movement in provisions (holiday pay, long service leave, sick leave and doubtful debts)

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 disposals of assets temporary difference $119,000 @28% = $34,000 and

Movement in provisions temporary difference $22,000 @28% = $6,000

Making temporary differences of $40,000.

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 has changed from the ACAM to ABAA. This has resulted in an increased cost allocation of $784,000.

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 has changed from the ACAM to ABAA. This has resulted in an asset allocation that reduces the regulatory asset base by $1.8million. The asset reclassification identified in box 4 has 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 $1million 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, a including the value of the expenditure the purpose of the expenditure, and the operational expenditure categories the expenditure relates to.

Box 10: Explanation of operational expenditure for the disclosure year
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 are over target by $493,000 due the unexpectedly high level of industrial connections.
- Asset relocations are $142,000 under target due cable costs previously included in Bateup Road Feed being transferred to various system growth projects.
- Asset replacement and renewal costs are 6% over target. Pole replacements are $683,000 above target due to the large number of reconductoring jobs. Cable replacements are $551,000 under target as these have been delayed due a change in priority.
- Reliability, safety and environment – quality of supply is under target by $482,000. This is mainly due to the 1MVA Generator Replacement project being delayed until the next year. It is underway now.
- Reliability, safety and environment – legislative and regulatory is on target.
- Reliability, safety and environment – Other reliability, safety and environment is under target by $243,000. This is due to the Lead Insulation Platformmount Transformers project's priority being reassessed and deferred.
- System Growth is $3.7 million under target with the new Wakapuaka Zone Substation and related 33kV Cable Extension projects being delayed due to resource consent and planning delays.

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

Operational Expenditure

- $200,000 of voltage support was categorised as service interruption and emergencies in the target calculations. It has been correctly categorised as routine and corrective maintenance in schedule 6b.
- Service interruptions and emergencies costs $396,000 under target. The above miscategorised of voltage support accounts for $200,000 of the variance. There was $60,000 more recovered faults than anticipated. The balance of the variance relates to 31 March 2018 accrued estimated storm damage actually being capital.
- Vegetation management is 7% above target due to the increase in contract and traffic management costs, and survey programme acceleration.
- Routine and corrective maintenance and inspection costs are $335,000 above target. $200,000 of this is explained by the above recategorisation of the voltage support costs, $52,000 relates to the increase in the 66kV line surveys. The balance is small unders and overs in the other expenditure.
- Asset replacement and renewal expenditure is 10% less than target, with some planned opex ending up as capex, and less distribution substation maintenance than budgeted due to the completion of the tap change programme earlier than anticipated.
- Non-network expenditure is close to target. System operations and network support is 7% above budget principally due to an increase in staff numbers. Business support is 6% under budget mainly due to the actual cost allocation to the non-regulatory business being higher than anticipated.

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

Line charge revenue is 2% above target.The primary reason for this variance is that volumes billed were higher than expected. Not only were the kWh volumes injected into the network up 2% on what was forecast/targeted, retailers reporting lower losses than budget and previous years. Irrigators were one identifiable sector that had an impact on the higher volumes with the dryer than normal summer period.

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 outage events was significantly over target for the year (106 vs target 75). Unplanned SAIDI was impacted by three traffic related events affecting the single 33kV line of supply along the Appleby Highway to our Mapua substation. These accumulated 34 SAIDI points. A new cable circuit bypassing the Appleby Highway circuit is under construction.

Reliability from planned outages was impacted with the commencement of the light copper conductor replacement programme. This caused planned SAIDI to be also significantly exceeded (134 vs target 75). Network Tasman Limited exceeded its Commerce Commission overall reliability limit for SAIDI for the first time. The light copper conductor replacement programme will continue for 9 years and due to the nature of the work, mitigation by the use of generators is limited. Our internal SAIDI target for planned outages has been raised to 100 points for the next nine years accordingly.

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 had 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

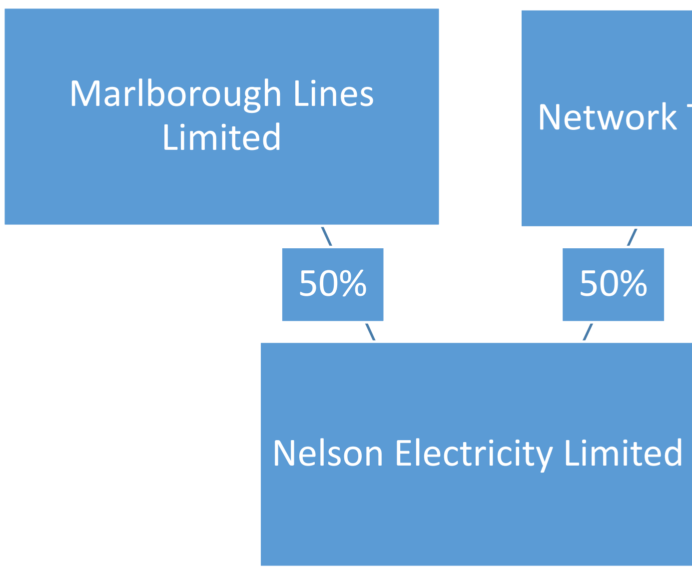
18.2 for each error, reference to the web address where the disclosure made in accordance with clause 2.12.1 is publicly disclosed.

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,



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	4
Electricity Authority Levy	13
Total Annual Charge	**20**

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 transactions 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 costs 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 ($4,000) 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 2019

Schedule 14a Mandatory Explanatory Notes on Forecast Information

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

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.

2. This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)

3. In the box below, comment on the difference between nominal and constant price capital expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts
An inflation factor of 2% has been applied from the 2020 year.

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

4. In the box below, comment on the difference between nominal and constant price operational expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts
An inflation factor of 2 % has been applied from the 2020 year.

Company Name	Network Tasman Limited
For Year Ended	31 March 2019

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

Tel: 64 3 989 3600
Freephone: 0800 508 098
Fax: 64 3 989 3631
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

30 August 2019

Independent Assurance Report

To the directors of Network Tasman Limited and the Commerce Commission

The Auditor-General is the auditor of Network Tasman Limited (the Company). The Auditor-General has appointed me, John Mackey, using the staff and resources of Audit New Zealand, to provide an opinion, on his behalf, on:

- Whether the information ('the Disclosure Information') required to be disclosed in accordance with the Electricity Distribution Information Disclosure Determination 2012 ('the Information Disclosure Determination') for the disclosure year ended 31 March 2019, has been prepared, in all material respects, in accordance with the Information Disclosure Determination.

  The Disclosure Information required to be reported by the Company, and audited by the Auditor-General, under the Information Disclosure Determination in schedules 1 to 4, 5a to 5g, 6a and 6b, 7, the disclosure that shows the connection between the Company and the related parties with which it has had related party transactions in the disclosure year, and the explanatory notes in boxes 1 to 11 in Schedule 14.

- Whether the Company's basis for valuation of related party transactions ('the Related Party Transaction Information') for the disclosure year ended 31 March 2019, has been prepared, in all material respects, in accordance with clause 2.3.6 of the Information Disclosure Determination, and clauses 2.2.11(1)(g) and 2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012 ('the Input Methodologies Determination').

Opinion

In our opinion:

- as far as appears from an examination of them, 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 and has been sourced, where appropriate, from the Company's financial and non-financial systems;

- the Disclosure Information complies, in all material respects, with the Information Disclosure Determination; and

- the Related Party Transaction Information complies, in all material respects, with the Information Disclosure Determination and the Input Methodologies Determination.

In forming our opinion, we have obtained sufficient recorded evidence and all the information and explanations we have required.

Basis for opinion

We conducted our engagement in accordance with the International Standard on Assurance Engagements (New Zealand) 3000 (Revised): *Assurance Engagements Other Than Audits or Reviews of Historical Financial Information* and the Standard on Assurance Engagements 3100 (Revised): *Compliance Engagements* issued by the New Zealand Auditing and Assurance Standards Board. Copies of these standards are available on the External Reporting Board's website.

These standards require that we comply with ethical requirements and plan and perform our assurance engagement to provide reasonable assurance about whether the Disclosure Information has been prepared, in all material respects, with the Information Disclosure Determination, and about whether the Related Party Transaction Information has been prepared, in all material respects, with the Information Disclosure Determination and the Input Methodologies Determination. Reasonable assurance is a high level of assurance.

We have performed procedures to obtain evidence about the amounts and disclosures in the Disclosure Information, and the basis of valuation in the Related Party Transaction Information. The procedures selected depend on our judgement, including the assessment of the risks of material misstatement of the Disclosure Information and the Related Party Transaction Information, whether due to fraud, error or non-compliance with the Information Disclosure Determination or the Input Methodologies Determination. In making those risk assessments, we considered internal control relevant to the Company's preparation of the Disclosure Information and the Related Party Transaction Information in order to design procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.

Scope and inherent limitations

Because of the inherent limitations of a reasonable assurance engagement, and the test basis of the procedures performed, it is possible that fraud, error or non-compliance may occur and not be detected.

We did not examine every transaction, adjustment or event underlying the Disclosure Information or the Related Party Transaction Information, nor do we guarantee complete accuracy of the Disclosure Information or the Related Party Transaction Information. Also we did not evaluate the security and controls over the electronic publication of the Disclosure Information or the Related Party Transaction Information.

The opinion expressed in this independent assurance report has been formed on the above basis.

Key Audit Matters

Key audit 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 audit, and in forming our opinion. We do not provide a separate opinion on these matters.

Key audit matter	How our procedures addressed the key audit matter
Cost allocation	
The Information Disclosure Determination and the Input Methodologies 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 Input Methodologies Determination sets out the rules and processes for allocating non-directly attributable costs. This is a key audit matter because of the professional judgement involved in determining and applying the method to allocate non-directly attributable costs to the Company's regulated services noting the allocation rules were modified for this year.	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 Information Disclosure Determination and the Input Methodologies 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 2019, 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 Information Disclosure Determination and the Input Methodologies Determination; • reviewing the Company's judgements in determining and applying appropriate methods to allocate non-directly attributable costs and assessing if the methods complies with the Information Disclosure Determination and the Input Methodologies Determination; and • testing a sample of cost allocation calculations.
Valuation of related-party transactions at arm's-length	
The Information Disclosure Determination and the Input Methodologies Determination place a requirement on the Company to value related-party procurement transactions at a value not greater than arm's-length. In other words, the value at which a transaction, with the same terms and conditions, would be entered into between a willing seller and a willing buyer who are unrelated and who are acting	We obtained an understanding of the Company's approach to identifying and valuing related-party transactions at arm's-length in accordance with the Information Disclosure Determination and the Input Methodologies Determination. The procedures we carried out, to satisfy ourselves that related-party transactions are appropriately identified and valued at a value not greater than arm's-length, included:

Key audit matter	How our procedures addressed the key audit matter
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 it is a new requirement that involves considerable judgement by Company personnel. In turn, verification of the appropriate assignment of an objective arm's-length valuation, to related-party transactions requires, the exercise of significant professional judgement by the auditor.	• 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 Information Disclosure Determination and the Input Methodologies Determination.

Directors' responsibility for the preparation of the Disclosure Information and Related Party Transaction Information

The directors of the Company are responsible for the preparation of:

- the Disclosure Information in accordance with the Information Disclosure Determination; and
- the Related Party Transaction Information in accordance with the Information Disclosure Determination and the Input Methodologies Determination.

The directors are responsible for such internal control as the directors determine is necessary to enable the preparation of the Disclosure Information and the Related Party Transaction Information that are free from material misstatement.

Our responsibility for the audit of the Disclosure Information and the Related Party Transaction Information

Our responsibility is to express an opinion that provides reasonable assurance on whether:

- the Disclosure Information has been prepared, in all material respects, in accordance with the Information Disclosure Determination; and
- the Related Party Transaction Information has been prepared, in all material respects, in accordance with the Information Disclosure Determination and the Input Methodologies Determination.

Independence and quality control

When carrying out the engagement, 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 (Revised) issued by the New Zealand Auditing and Assurance Standards Board;
- the independence requirements specified in the Information Disclosure Determination; and
- the Auditor-General's quality control requirements, which incorporate the quality control requirements of Professional and Ethical Standard 3 (Amended) issued by the New Zealand Auditing and Assurance Standards Board.

The Auditor-General, and his employees, and Audit New Zealand and its employees may deal with the Company on normal terms within the ordinary course of trading activities of the Company. Other than any dealings on normal terms within the ordinary course of business, this engagement, the default price-quality path assurance engagement, and the annual audit of the Company's financial statements, we have no relationship with or interests in the Company.

Use of this report

This independent assurance report has been prepared solely for the directors of the Company and for the Commerce Commission for the purpose of providing those parties with reasonable assurance about whether the Disclosure Information has been prepared, in all material respects, in accordance with the Information Disclosure Determination and whether the Related Party Transaction Information has been prepared, in all material respects, in accordance with the Information Disclosure Determination and the Input Methodologies Determination. We disclaim any assumption of responsibility for any reliance on this report to any person other than the directors of the Company or the Commerce Commission, or for any other purpose than that for which it was prepared.

John Mackey
Audit New Zealand
On behalf of the Auditor-General
Christchurch, New Zealand
30 August 2019