EDB Information Disclosure Requirements
Information Templates
for
Schedules 1–10

Company Name	Network Tasman Limited
Disclosure Date	31 August 2017
Disclosure Year (year ended)	31 March 2017

Templates for Schedules 1–10 excluding 5f–5g

Template Version 4.1. Prepared 24 March 2015

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2017**

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**	16,791	264	85,967	2,881	25,754
10	Network	8,675	137	44,417	1,488	13,306
11	Non-network	8,115	128	41,550	1,392	12,448
12						
13	**Expenditure on assets**	9,522	150	48,750	1,634	14,604
14	Network	9,235	145	47,283	1,584	14,165
15	Non-network	286	5	1,467	49	439
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**	72,054	1,134
20	Standard consumer line charge revenue	80,919	1,025
21	Non-standard consumer line charge revenue	35,472	1,417,000
22			

23

1(iii): Service intensity measures

sch ref			
24			
25	Demand density	39	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
26	Volume density	172	*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	15,742	*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	10,316	23.43%
33	Pass-through and recoverable costs excluding financial incentives and wash-ups	13,340	30.30%
34	Total depreciation	6,779	15.40%
35	Total revaluations	3,531	8.02%
36	Regulatory tax allowance	982	2.23%
37	Regulatory profit/(loss) including financial incentives and wash-ups	16,144	36.67%
38	**Total regulatory income**	44,030	
39			

40

1(v): Reliability

sch ref			
41			
42	Interruption rate	9.49	*Interruptions per 100 circuit km*

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2017**

SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

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

sch ref			CY-2	CY-1	Current Year CY
7	**2(i): Return on Investment**				
8			31 Mar 15	31 Mar 16	31 Mar 17
9	**ROI – comparable to a post tax WACC**		%	%	%
10		Reflecting all revenue earned	6.66%	7.83%	9.59%
11		Excluding revenue earned from financial incentives	6.66%	5.65%	7.61%
12		Excluding revenue earned from financial incentives and wash-ups	5.34%	5.65%	7.73%
13					
14		**Mid-point estimate of post tax WACC**	6.10%	5.37%	4.77%
15		25th percentile estimate	5.39%	4.66%	4.05%
16		75th percentile estimate	6.82%	6.09%	5.48%
17					
18					
19	**ROI – comparable to a vanilla WACC**				
20		Reflecting all revenue earned	7.44%	8.48%	10.14%
21		Excluding revenue earned from financial incentives	7.44%	6.30%	8.15%
22		Excluding revenue earned from financial incentives and wash-ups	6.13%	6.30%	8.27%
23					
24		**WACC rate used to set regulatory price path**	8.77%	7.19%	7.19%
25					
26		**Mid-point estimate of vanilla WACC**	6.89%	6.02%	5.31%
27		25th percentile estimate	6.17%	5.30%	4.59%
28		75th percentile estimate	7.60%	6.74%	6.03%
29					
30	**2(ii): Information Supporting the ROI**			($000)	
31					
32		Total opening RAB value	163,098		
33	*plus*	Opening deferred tax	(495)		
34	**Opening RIV**			162,603	
35					
36	**Line charge revenue**			44,269	
37					
38		Expenses cash outflow	23,656		
39	*add*	Assets commissioned	5,612		
40	*less*	Asset disposals	825		
41	*add*	Tax payments	306		
42	*less*	Other regulated income	(239)		
43	**Mid-year net cash outflows**			28,988	
44					
45	**Term credit spread differential allowance**			–	
46					
47		Total closing RAB value	164,637		
48	*less*	Adjustment resulting from asset allocation	(0)		
49	*less*	Lost and found assets adjustment	–		
50	*plus*	Closing deferred tax	(1,171)		
51	**Closing RIV**			163,466	
52					
53	**ROI – comparable to a vanilla WACC**				10.14%
54					
55		Leverage (%)			44%
56		Cost of debt assumption (%)			4.41%
57		Corporate tax rate (%)			28%
58					
59	**ROI – comparable to a post tax WACC**				9.59%
60					

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2017**

SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

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

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sch ref

2(iii): Information Supporting the Monthly ROI

Opening RIV	N/A

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

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

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

Year-end ROI – comparable to a vanilla WACC	7.33%
Year-end ROI – comparable to a post tax WACC	6.79%

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

2(v): Financial Incentives and Wash-Ups

Net recoverable costs allowed under incremental rolling incentive scheme	–	
Purchased assets – avoided transmission charge	4,270	
Energy efficiency and demand incentive allowance	–	
Quality incentive adjustment	–	
Other financial incentives	–	
Financial incentives		4,270
Impact of financial incentives on ROI		1.99%
Input methodology claw-back	–	
Recoverable customised price-quality path costs	–	
Catastrophic event allowance	–	
Capex wash-up adjustment	(256)	
Transmission asset wash-up adjustment	–	
2013–2015 NPV wash-up allowance	–	
Reconsideration event allowance	–	
Other wash-ups	–	
Wash-up costs		(256)
Impact of wash-up costs on ROI		–0.12%

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2017**

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	44,269
10	*plus*	Gains / (losses) on asset disposals	(359)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)	120
12			
13		**Total regulatory income**	44,030
14		**Expenses**	
15	*less*	Operational expenditure	10,316
16			
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups	13,340
18			
19		**Operating surplus / (deficit)**	20,374
20			
21	*less*	Total depreciation	6,779
22			
23	*plus*	Total revaluations	3,531
24			
25		**Regulatory profit / (loss) before tax**	17,126
26			
27	*less*	Term credit spread differential allowance	–
28			
29	*less*	Regulatory tax allowance	982
30			
31		**Regulatory profit/(loss) including financial incentives and wash-ups**	16,144
32			

sch ref			
33	**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	**($000)**	
34	**Pass through costs**		
35	Rates	202	
36	Commerce Act levies	88	
37	Industry levies	154	
38	CPP specified pass through costs	–	
39	**Recoverable costs excluding financial incentives and wash-ups**		
40	Electricity lines service charge payable to Transpower	10,780	
41	Transpower new investment contract charges	330	
42	System operator services	–	
43	Distributed generation allowance	1,786	
44	Extended reserves allowance	–	
45	Other recoverable costs excluding financial incentives and wash-ups	–	
46	**Pass-through and recoverable costs excluding financial incentives and wash-ups**		13,340
47			

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2017**

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 16**	**31 Mar 17**
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 12	–	–
58	CY-4	31 Mar 13	–	–
59	CY-3	31 Mar 14	–	–
60	CY-2	31 Mar 15	–	–
61	CY-1	31 Mar 16	–	–
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**
For Year Ended	**31 March 2017**

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

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

sch ref

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

	for year ended	RAB 31 Mar 13 ($000)	RAB 31 Mar 14 ($000)	RAB 31 Mar 15 ($000)	RAB 31 Mar 16 ($000)	RAB 31 Mar 17 ($000)
Total opening RAB value		152,910	150,493	155,232	161,816	163,098
less **Total depreciation**		6,468	6,574	6,778	6,937	6,779
plus **Total revaluations**		1,313	2,307	130	948	3,531
plus **Assets commissioned**		3,113	9,280	13,773	7,777	5,612
less **Asset disposals**		375	274	541	506	825
plus **Lost and found assets adjustment**		–	–	–	–	–
plus **Adjustment resulting from asset allocation**		(0)	0	(0)	0	(0)
Total closing RAB value		150,493	155,232	161,816	163,098	164,637

4(ii): Unallocated Regulatory Asset Base

	Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
Total opening RAB value		163,218		163,098
less				
Total depreciation		6,842		6,779
plus				
Total revaluations		3,534		3,531
plus				
Assets commissioned (other than below)	5,612		5,612	
Assets acquired from a regulated supplier	–		–	
Assets acquired from a related party	–		–	
Assets commissioned		5,612		5,612
less				
Asset disposals (other than below)	825		825	
Asset disposals to a regulated supplier	–		–	
Asset disposals to a related party	–		–	
Asset disposals		825		825
plus **Lost and found assets adjustment**		–		–
plus **Adjustment resulting from asset allocation**				(0)
Total closing RAB value		164,697		164,637

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

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2017**

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				1,226
55		CPI_4^{-4}				1,200
56		Revaluation rate (%)				2.17%
57						
58			**Unallocated RAB ***		**RAB**	
59			**($000)**	**($000)**	**($000)**	**($000)**
60		Total opening RAB value	163,218		163,098	
61	*less*	Opening value of fully depreciated, disposed and lost assets	127		127	
62						
63		Total opening RAB value subject to revaluation	163,091		162,971	
64		**Total revaluations**		3,534		3,531
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**		2,451		2,451
69	*plus*	Capital expenditure	5,902		5,902	
70	*less*	Assets commissioned	5,612		5,612	
71	*plus*	Adjustment resulting from asset allocation			–	
72		**Works under construction - current disclosure year**		2,741		2,741
73						
74		Highest rate of capitalised finance applied				–
75						

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2017**

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

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

sch ref

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

sch ref		Unallocated RAB *		RAB	
78		**($000)**	**($000)**	**($000)**	**($000)**
79	Depreciation - standard	6,654		6,591	
80	Depreciation - no standard life assets	188		188	
81	Depreciation - modified life assets	–		–	
82	Depreciation - alternative depreciation in accordance with CPP	–		–	
83	**Total depreciation**		6,842		6,779
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	There are no assets with changes to depreciation				
89					
90					
91					
92					
93					
94					

95 ** include additional rows if needed*

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

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

sch ref			**Subtransmission lines**	**Subtransmission cables**	**Zone substations**	**Distribution and LV lines**	**Distribution and LV cables**	**Distribution substations and transformers**	**Distribution switchgear**	**Other network assets**	**Non-network assets**	**Total**
99		**Total opening RAB value**	8,170	9,516	22,393	24,449	51,852	22,373	7,018	14,194	3,133	163,098
100	*less*	Total depreciation	273	191	736	1,740	1,396	1,050	314	887	192	6,779
101	*plus*	Total revaluations	178	206	482	529	1,129	484	165	292	66	3,531
102	*plus*	Assets commissioned	31	–	113	1,175	1,008	1,415	664	1,013	193	5,612
103	*less*	Asset disposals	–	–	–	32	–	148	536	5	104	825
104	*plus*	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
105	*plus*	Adjustment resulting from asset allocation	–	–	–	–	–	–	–	–	–	–
106	*plus*	Asset category transfers	–	–	(170)	(28)	269	17	610	(698)	–	–
107		**Total closing RAB value**	8,106	9,531	22,082	24,353	52,862	23,091	7,607	13,909	3,096	164,637
108												
109		**Asset Life**										
110		Weighted average remaining asset life	39.0	49.7	27.7	74.9	45.7	31.2	24.9	23.7	23.8	(years)
111		Weighted average expected total asset life	58.6	56.1	39.7	119.3	60.3	51.2	39.5	40.0	30.0	(years)

Should have read

	Distribution and LV lines
Asset Life	
Weighted average remaining asset life	29.1
Weighted average expected total asset life	58.9

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2017**

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**			17,126
9					
10	*plus*	Income not included in regulatory profit / (loss) before tax but taxable	5	*	
11		Expenditure or loss in regulatory profit / (loss) before tax but not deductible	20	*	
12		Amortisation of initial differences in asset values	3,240		
13		Amortisation of revaluations	505		
14					3,770
15					
16	*less*	Total revaluations	3,531		
17		Income included in regulatory profit / (loss) before tax but not taxable	–	*	
18		Discretionary discounts and customer rebates	10,320		
19		Expenditure or loss deductible but not in regulatory profit / (loss) before tax	451	*	
20		Notional deductible interest	3,088		
21					17,390
22					
23		**Regulatory taxable income**			3,506
24					
25	*less*	Utilised tax losses	–		
26		Regulatory net taxable income			3,506
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**			982
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	88,645		
37	*less*	Amortisation of initial differences in asset values	3,240		
38	*plus*	Adjustment for unamortised initial differences in assets acquired	–		
39	*less*	Adjustment for unamortised initial differences in assets disposed	19		
40		Closing unamortised initial differences in asset values			85,386
41					
42		Opening weighted average remaining useful life of relevant assets (years)			27
43					

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2017**

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				
44		**5a(iv): Amortisation of Revaluations**		**($000)**
45				
46		Opening sum of RAB values without revaluations	151,746	
47				
48		Adjusted depreciation	6,274	
49		Total depreciation	6,779	
50		Amortisation of revaluations		505
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**	(495)	
61				
62	*plus*	Tax effect of adjusted depreciation	1,757	
63				
64	*less*	Tax effect of tax depreciation	1,401	
65				
66	*plus*	Tax effect of other temporary differences*	(52)	
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	72	
73				
74	*plus*	Deferred tax cost allocation adjustment	0	
75				
76		**Closing deferred tax**		(1,171)
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**	61,414	
84	*less*	Tax depreciation	5,005	
85	*plus*	Regulatory tax asset value of assets commissioned	5,893	
86	*less*	Regulatory tax asset value of asset disposals	280	
87	*plus*	Lost and found assets adjustment	–	
88	*plus*	Adjustment resulting from asset allocation	–	
89	*plus*	Other adjustments to the RAB tax value	–	
90		**Closing sum of regulatory tax asset values**		62,022

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2017**

SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

This schedule provides information on the valuation of related party transactions, in accordance with section 2.3.6 and 2.3.7 of the ID 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

sch ref	5b(i): Summary—Related Party Transactions	($000)
7		
8	Total regulatory income	71
9	Operational expenditure	
10	Capital expenditure	
11	Market value of asset disposals	
12	Other related party transactions	

13 5b(ii): Entities Involved in Related Party Transactions

sch ref	Name of related party	Related party relationship
14		
15	Nelson Electricity Ltd	50% owned by Network Tasman Limited
16		
17		
18		
19		
20	** include additional rows if needed*	

21 5b(iii): Related Party Transactions

sch ref	Name of related party	Related party transaction type	Description of transaction	Value of transaction ($000)	Basis for determining value
22					
23	Nelson Electricity Ltd	Sales	Management services fee for engineering support	49	ID clause 2.3.7(2)(b)
24	Nelson Electricity Ltd	Sales	Electricity Authority levies on-charged	22	ID clause 2.3.7(2)(c)
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38	** include additional rows if needed*				

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2017**

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	Cost of executing an interest rate swap	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	44%	
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 2017**

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

5d(i): Operating Cost Allocations

	Value allocated ($000s)				
	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
Service interruptions and emergencies					
Directly attributable		944			
Not directly attributable		–		–	
Total attributable to regulated service		944			
Vegetation management					
Directly attributable		925			
Not directly attributable		–		–	
Total attributable to regulated service		925			
Routine and corrective maintenance and inspection					
Directly attributable		1,607			
Not directly attributable		–		–	
Total attributable to regulated service		1,607			
Asset replacement and renewal					
Directly attributable		1,854			
Not directly attributable		–		–	
Total attributable to regulated service		1,854			
System operations and network support					
Directly attributable		2,134			
Not directly attributable		–		–	
Total attributable to regulated service		2,134			
Business support					
Directly attributable		2,852			
Not directly attributable		–		–	
Total attributable to regulated service		2,852			
Operating costs directly attributable		10,316			
Operating costs not directly attributable	–	–	–	–	–
Operational expenditure		10,316			

5d(ii): Other Cost Allocations

Pass through and recoverable costs	($000)
Pass through costs	
Directly attributable	444
Not directly attributable	–
Total attributable to regulated service	444
Recoverable costs	
Directly attributable	12,896
Not directly attributable	–
Total attributable to regulated service	12,896

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

Change in cost allocation 1

			($000)	
			CY-1	Current Year (CY)
Cost category		Original allocation	–	
Original allocator or line items		New allocation	–	
New allocator or line items		Difference	–	–

Rationale for change

Change in cost allocation 2

			($000)	
			CY-1	Current Year (CY)
Cost category		Original allocation	–	
Original allocator or line items		New allocation	–	
New allocator or line items		Difference	–	–

Rationale for change

Change in cost allocation 3

			($000)	
			CY-1	Current Year (CY)
Cost category		Original allocation	–	
Original allocator or line items		New allocation	–	
New allocator or line items		Difference	–	–

Rationale for change

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

† include additional rows if needed

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2017**

SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

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

sch ref

5e(i): Regulated Service Asset Values

	Value allocated ($000s) Electricity distribution services
Subtransmission lines	
Directly attributable	8,106
Not directly attributable	–
Total attributable to regulated service	8,106
Subtransmission cables	
Directly attributable	9,531
Not directly attributable	–
Total attributable to regulated service	9,531
Zone substations	
Directly attributable	22,082
Not directly attributable	–
Total attributable to regulated service	22,082
Distribution and LV lines	
Directly attributable	24,353
Not directly attributable	–
Total attributable to regulated service	24,353
Distribution and LV cables	
Directly attributable	52,862
Not directly attributable	–
Total attributable to regulated service	52,862
Distribution substations and transformers	
Directly attributable	23,091
Not directly attributable	–
Total attributable to regulated service	23,091
Distribution switchgear	
Directly attributable	7,607
Not directly attributable	–
Total attributable to regulated service	7,607
Other network assets	
Directly attributable	13,743
Not directly attributable	166
Total attributable to regulated service	13,909
Non-network assets	
Directly attributable	3,096
Not directly attributable	–
Total attributable to regulated service	3,096
Regulated service asset value directly attributable	164,471
Regulated service asset value not directly attributable	166
Total closing RAB value	164,637

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

Change in asset value allocation 1			($000) CY-1	Current Year (CY)
Asset category	0	Original allocation	–	–
Original allocator or line items	0	New allocation	–	–
New allocator or line items	0	Difference	–	–
Rationale for change				

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

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

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

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2017**

SCHEDULE 5f: REPORT SUPPORTING COST ALLOCATIONS

This schedule requires additional detail on the asset allocation methodology applied in allocating asset values that are not directly attributable, to support the information provided in Schedule 5d (Cost allocations). This schedule is not required to be publicly disclosed, but must be disclosed to the Commission.

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

Have costs been allocated in aggregate using ACAM in accordance with clause 2.1.1(3) of the IM Determination?	Yes

Line Item*	Allocation methodology type	Cost allocator	Allocator type	Allocator Metric (%)		Value allocated ($000)				OVABAA allocation increase ($000)
				Electricity distribution services	Non-electricity distribution services	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	
Service interruptions and emergencies										
all				100.00%					-	
									-	
									-	
									-	
Not directly attributable						-	-	-	-	-
Vegetation management										
all				100.00%					-	
									-	
									-	
									-	
Not directly attributable						-	-	-	-	-
Routine and corrective maintenance and inspection										
all				100.00%					-	
									-	
									-	
									-	
Not directly attributable						-	-	-	-	-
Asset replacement and renewal										
all				100.00%					-	
									-	
									-	
									-	
Not directly attributable						-	-	-	-	-

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2017**

SCHEDULE 5f: REPORT SUPPORTING COST ALLOCATIONS

This schedule requires additional detail on the asset allocation methodology applied in allocating asset values that are not directly attributable, to support the information provided in Schedule 5d (Cost allocations). This schedule is not required to be publicly disclosed, but must be disclosed to the Commission.

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												
37	**System operations and network support**											
38		all				100.00%					-	
39											-	
40											-	
41											-	
42	**Not directly attributable**							-	-	-	-	-
43	**Business support**											
44		all				100.00%					-	
45											-	
46											-	
47											-	
48	**Not directly attributable**							-	-	-	-	-
49												
50	**Operating costs not directly attributable**							-	-	-	-	-
51												
52	**Pass through and recoverable costs**											
53	**Pass through costs**											
54		all				100.00%					-	
55											-	
56											-	
57											-	
58	**Not directly attributable**							-	-	-	-	-
59	**Recoverable costs**											
60		all				100.00%					-	
61											-	
62											-	
63											-	
64	**Not directly attributable**							-	-	-	-	-
65	** include additional rows if needed*											

Company Name **Network Tasman Limited**
For Year Ended **31 March 2017**

SCHEDULE 5g: REPORT SUPPORTING ASSET ALLOCATIONS

This schedule requires additional detail on the asset allocation methodology applied in allocating asset values that are not directly attributable, to support the information provided in Schedule 5e (Report on Asset Allocations). This schedule is not required to be publicly disclosed, but must be disclosed to the Commission.
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 Have assets been allocated in aggregate using ACAM in accordance with clause 2.1.1(3) of the IM Determination? Yes

9

sch ref	Line Item*	Allocation methodology type	Allocator	Allocator type	Allocator Metric (%)		Value allocated ($000)				OVABAA allocation increase ($000)
					Electricity distribution services	Non-electricity distribution services	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	
12	**Subtransmission lines**										
13	all				100.00%					-	
14										-	
15										-	
16										-	
17	**Not directly attributable**						-	-	-	-	-
18	**Subtransmission cables**										
19	all				100.00%					-	
20										-	
21										-	
22										-	
23	**Not directly attributable**						-	-	-	-	-
24	**Zone substations**										
25	all				100.00%					-	
26										-	
27										-	
28										-	
29	**Not directly attributable**						-	-	-	-	-
30	**Distribution and LV lines**										
31	all				100.00%					-	
32										-	
33										-	
34										-	
35	**Not directly attributable**						-	-	-	-	-

Company Name	Network Tasman Limited
For Year Ended	31 March 2017

SCHEDULE 5g: REPORT SUPPORTING ASSET ALLOCATIONS

This schedule requires additional detail on the asset allocation methodology applied in allocating asset values that are not directly attributable, to support the information provided in Schedule 5e (Report on Asset Allocations). This schedule is not required to be publicly disclosed, but must be disclosed to the Commission.
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												
36	**Distribution and LV cables**											
37		all				100.00%					-	
38											-	
39											-	
40											-	
41	**Not directly attributable**							-	-	-	-	-
42												
43	**Distribution substations and transformers**											
44		all				100.00%					-	
45											-	
46											-	
47											-	
48	**Not directly attributable**							-	-	-	-	-
49												
50	**Distribution switchgear**											
51		all				100.00%					-	
52											-	
53											-	
54											-	
55	**Not directly attributable**							-	-	-	-	-
56	**Other network assets**											
57		Fibre to Substation Assets	ACAM	luation of actual co:	Causal	72.17%	27.83%		166	64	230	
58		Other				100.00%			13,743	-	13,743	
59											-	
60											-	
61	**Not directly attributable**							-	13,909	64	13,973	-
62	**Non-network assets**											
63		all				100.00%					-	
64											-	
65											-	
66											-	
67	**Not directly attributable**							-	-	-	-	-
68												
69	**Regulated service asset value not directly attributable**							-	13,909	64	13,973	-
70	** include additional rows if needed*											

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2017**

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		836
9		System growth		998
10		Asset replacement and renewal		2,134
11		Asset relocations		1,107
12		Reliability, safety and environment:		
13		Quality of supply	416	
14		Legislative and regulatory	2	
15		Other reliability, safety and environment	181	
16		**Total reliability, safety and environment**		599
17		**Expenditure on network assets**		5,674
18		Expenditure on non-network assets		176
19				
20		**Expenditure on assets**		5,850
21	*plus*	Cost of financing		–
22	*less*	Value of capital contributions		105
23	*plus*	Value of vested assets		157
24				
25		**Capital expenditure**		5,902
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		1,055
29		Research and development		–
30		**6a(iii): Consumer Connection**		
31		*Consumer types defined by EDB**	**($000)**	**($000)**
32		Consumers 20kVA and less	259	
33		Consumers greater than 20kVA	577	
34		–	–	
35		–	–	
36		–	–	
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		836
39				
40	*less*	Capital contributions funding consumer connection expenditure	14	
41		**Consumer connection less capital contributions**		822
42		**6a(iv): System Growth and Asset Replacement and Renewal**		**Asset Replacement and**
43			**System Growth**	**Renewal**
44			**($000)**	**($000)**
45		Subtransmission	1	52
46		Zone substations	132	457
47		Distribution and LV lines	183	1,108
48		Distribution and LV cables	366	–
49		Distribution substations and transformers	140	226
50		Distribution switchgear	176	176
51		Other network assets	–	115
52		**System growth and asset replacement and renewal expenditure**	998	2,134
53	*less*	Capital contributions funding system growth and asset replacement and renewal	14	77
54		**System growth and asset replacement and renewal less capital contributions**	984	2,057
55				
56		**6a(v): Asset Relocations**		
57		*Project or programme**	**($000)**	**($000)**
58		Underground 400v & 11kV Lines High Street Motueka	1,055	
59		–	–	
60		–	–	
61		–	–	
62		–	–	
63		** include additional rows if needed*		
64		All other projects or programmes - asset relocations	52	
65		**Asset relocations expenditure**		1,107
66	*less*	Capital contributions funding asset relocations	–	
67		**Asset relocations less capital contributions**		1,107

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2017**

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

6a(vi): Quality of Supply

	*Project or programme**	($000)	($000)
		–	
		–	
		–	
		–	
		–	
	** include additional rows if needed*		
	All other projects programmes - quality of supply	416	
	Quality of supply expenditure		416
less	Capital contributions funding quality of supply	–	
	Quality of supply less capital contributions		416

6a(vii): Legislative and Regulatory

	*Project or programme**	($000)	($000)
		–	
		–	
		–	
		–	
		–	
	** include additional rows if needed*		
	All other projects or programmes - legislative and regulatory	2	
	Legislative and regulatory expenditure		2
less	Capital contributions funding legislative and regulatory	–	
	Legislative and regulatory less capital contributions		2

6a(viii): Other Reliability, Safety and Environment

	*Project or programme**	($000)	($000)
		–	
		–	
		–	
		–	
		–	
	** include additional rows if needed*		
	All other projects or programmes - other reliability, safety and environment	181	
	Other reliability, safety and environment expenditure		181
less	Capital contributions funding other reliability, safety and environment	–	
	Other reliability, safety and environment less capital contributions		181

6a(ix): Non-Network Assets

Routine expenditure

*Project or programme**	($000)	($000)
0	–	
0	–	
	–	
	–	
	–	
** include additional rows if needed*		
All other projects or programmes - routine expenditure	176	
Routine expenditure		176

Atypical expenditure

*Project or programme**	($000)	($000)
	–	
	–	
	–	
	–	
	–	
** include additional rows if needed*		
All other projects or programmes - atypical expenditure	–	
Atypical expenditure		–
Expenditure on non-network assets		176

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2017**

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	944	
9	Vegetation management	925	
10	Routine and corrective maintenance and inspection	1,607	
11	Asset replacement and renewal	1,854	
12	**Network opex**		5,330
13	System operations and network support	2,134	
14	Business support	2,852	
15	**Non-network opex**		4,986
16			
17	**Operational expenditure**		10,316
18	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
19	Energy efficiency and demand side management, reduction of energy losses		28
20	Direct billing*		–
21	Research and development		–
22	Insurance		288
23	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2017**

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	44,538	44,269	(1%)
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	520	836	61%
11	System growth	1,797	998	(44%)
12	Asset replacement and renewal	3,291	2,134	(35%)
13	Asset relocations	1,200	1,107	(8%)
14	Reliability, safety and environment:			
15	Quality of supply	113	416	268%
16	Legislative and regulatory	–	2	–
17	Other reliability, safety and environment	330	181	(45%)
18	**Total reliability, safety and environment**	443	599	35%
19	**Expenditure on network assets**	7,251	5,674	(22%)
20	Expenditure on non-network assets	451	176	(61%)
21	Expenditure on assets	7,702	5,850	(24%)
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	1,001	944	(6%)
24	Vegetation management	962	925	(4%)
25	Routine and corrective maintenance and inspection	1,672	1,607	(4%)
26	Asset replacement and renewal	2,357	1,854	(21%)
27	**Network opex**	5,992	5,330	(11%)
28	System operations and network support	2,032	2,134	5%
29	Business support	2,807	2,852	2%
30	**Non-network opex**	4,839	4,986	3%
31	**Operational expenditure**	10,831	10,316	(5%)
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	1,200	1,055	(12%)
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	56	28	(50%)
39	Direct billing	–	–	–
40	Research and development	–	–	–
41	Insurance	261	288	10%
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)*

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 **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)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)	Billed quantities by price component							
12					Price component	0STL	0TBS	0UNM	1ANY	1DAY	1NIT	1OPK	1WSR
13					Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	W/day	Daily	Daily	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh
15	0S	Unmetered Streetlamps	Standard	25	2,314	557,393	–	–	–	–	–	–	–
16	0TBS	Temporary Builders Supplies	Standard	–	–	–	2	–	–	–	–	–	–
17	0UNM	Unmetered Supplies	Standard	87	16	–	–	81	–	–	–	–	–
18	1	15 kVA Capacity	Standard	35,977	245,992	4,724	–	–	177,443	1,907	4,419	437	61,786
19	2	20 - 150 kVA Capacity	Standard	2,693	93,657	4,724	–	–	–	–	–	–	–
20	2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	2	7	–	–	–	–	–	–	–	–
21	2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	36	271	–	–	–	–	–	–	–	–
22	HLF	High Load Factor, 15-150kVA Capacity	Standard	52	10,806	–	–	–	–	–	–	–	–
23	31	Between 150 and 3000kVA	Standard	4	10,471	–	–	–	–	–	–	–	–
	33	Between 150 and 3000kVA	Standard	4	8,549	–	–	–	–	–	–	–	–
	34	Between 150 and 3000kVA	Standard	143	108,636	–	–	–	–	–	–	–	–
	35	Between 150 and 3000kVA	Standard	2	13,827	–	–	–	–	–	–	–	–
	6.1	> 3000,	Non-standard	1	104,495	–	–	–	–	–	–	–	–
	6.2	> 3000,	Non-standard	1	15,262	–	–	–	–	–	–	–	–
	CB	Cobb River Hydro	Non-standard	1	83	–	–	–	–	–	–	–	–
	0	0	[Select one]	–	–	–	–	–	–	–	–	–	–
	0	0	[Select one]	–	–	–	–	–	–	–	–	–	–
	0	0	[Select one]	–	–	–	–	–	–	–	–	–	–
24	0	0	[Select one]	–	–	–	–	–	–	–	–	–	–
25	*Add extra rows for additional consumer groups or price category codes as necessary*												
26			**Standard consumer totals**	39,025	494,546	566,841	2	81	177,443	1,907	4,419	437	61,786
27			**Non-standard consumer totals**	3	119,840	–	–	–	–	–	–	–	–
28			**Total for all consumers**	39,028	614,386	566,841	2	81	177,443	1,907	4,419	437	61,786

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

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)	Price component	0STL	0TBS	0UNM	1ANY	1DAY	1NIT	1OPK	1WSR
							Rate (eg, $ per day, $ per kWh, etc.)	W/day	Daily	Daily	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh
0S	Unmetered Streetlamps	Standard	$236	–	$158	$78		$236							
0TBS	Temporary Builders Supplies	Standard	–	–	–	–									
0UNM	Unmetered Supplies	Standard	$16	–	$11	$5				$16	–				
1	15 kVA Capacity	Standard	$21,301	–	$14,516	$6,785		$2			$16,345	$193	$136	$31	$2,627
2	20 - 150 kVA Capacity	Standard	$9,439	–	$6,787	$2,652		$2			($1)	–	–	–	–
2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	$1	–	$1	–									
2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	$31	–	$23	$8					–				–
HLF	High Load Factor, 15-150kVA Capacity	Standard	$700	–	$536	$164					($1)				
31	Between 150 and 3000kVA	Standard	$339	–	$147	$192		–	–	–	–	–	–	–	
33	Between 150 and 3000kVA	Standard	$392	–	$253	$139		–	–	–	–	–	–	–	–
34	Between 150 and 3000kVA	Standard	$6,581	–	$4,119	$2,462		–	–	–	–	–	–	–	–
35	Between 150 and 3000kVA	Standard	$638	–	$381	$257		–	–	–	–	–	–	–	–
6.1	> 3000,	Non-standard	$2,030	–	$215	$1,815		–	–	–	–	–	–	–	–
6.2	> 3000,	Non-standard	$593	–	$230	$363		–	–	–	–	–	–	–	–
NDL/New Connections	New Connectionns, NDL	Standard	$344	–	$344	–		–	–	–	–	–	–	–	–
Embedded generators	Cobb, Pupu etc	Non-standard	$1,628	–	$1,309	$319		–	–	–	–	–	–	–	–
0			–	–	–	–		–	–	–	–	–	–	–	–
Add extra rows for additional consumer groups or price category codes as necessary															
		Standard consumer totals	$40,018	–	$27,276	$12,742		$240	–	$16	$16,343	$193	$136	$31	$2,627
		Non-standard consumer totals	$4,251	–	$1,754	$2,497		–	–	–	–	–	–	–	–
		Total for all consumers	$44,269	–	$29,030	$15,239		$240	–	$16	$16,343	$193	$136	$31	$2,627

8(iii): Number of ICPs directly billed

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Number of directly billed ICPs at year end 7

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
Information is also required on the number of ICPs that are included in each consumer group or price category code, and

sch ref

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

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sch ref	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	2ANY	2DAY	2NIT	2OPK	2WSR	2LANY	2LDAY	2LNIT	2LOPK	2LWSR	2HANY	2HDAY	2HNIT	2HOPK	2HWSR	HLFANY	HLFDAY	HLFNIT	HLFOPK	HLFWSR	GENA
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	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh
14																								
15	0S	Unmetered Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
16	0TBS	Temporary Builders Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
17	0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
18	1	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1,589
19	2	20 - 150 kVA Capacity	Standard	65,011	16,788	7,921	258	3,679	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	128
20	2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	6	–	–	–	1	–	–	–	–	–	–
21	2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	–	–	–	–	–	197	18	13	–	43	–	–	–	–	–	–	–	–	–	–	4
22	HLF	High Load Factor, 15-150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	5,060	4,044	1,667	–	35	–
23	31	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	33	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1,106
	34	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2
	35	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	CB	Cobb River Hydro	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	0	0	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	0	0	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	0	0	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
24	0	0	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
25	*Add extra rows for additional consumer groups or price category codes as necessary*																							
26			**Standard consumer totals**	65,011	16,788	7,921	258	3,679	197	18	13	–	43	6	–	–	–	1	5,060	4,044	1,667	–	35	2,829
27			**Non-standard consumer totals**	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
28			**Total for all consumers**	65,011	16,788	7,921	258	3,679	197	18	13	–	43	6	–	–	–	1	5,060	4,044	1,667	–	35	2,829

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SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

This schedule requires the billed quantities and associated line charge revenues for each price category code used by the
Information is also required on the number of ICPs that are included in each consumer group or price category code, and

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

32
33

Row	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	2ANY	2DAY	2NIT	2OPK	2WSR	2LANY	2LDAY	2LNIT	2LOPK	2LWSR	2HANY	2HDAY	2HNIT	2HOPK	2HWSR	HLFANY	HLFDAY	HLFNIT	HLFOPK	HLFWSR	GENA
34/35				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	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh
37	0S	Unmetered Streetlamps	Standard																					
38	0TBS	Temporary Builders Supplies	Standard																					
39	0UNM	Unmetered Supplies	Standard																					
40	1	15 kVA Capacity	Standard	$1	–	–	–	–											–					
41	2	20 - 150 kVA Capacity	Standard	$5,271	$1,501	$213	$16	$138	$1		–		–							–	–			
	2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard						–				–	$1				–						
	2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	–	–	–		–	$23	$2	$1	–	$3											
	HLF	High Load Factor, 15-150kVA Capacity	Standard	$3	–	–		–											$115	$100	$12		–	
	31	Between 150 and 3000kVA	Standard																					
	33	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	34	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	35	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
42	6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
43	6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
44	NDL/New Connections	New Connectionns, NDL	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
45	Embedded generators	Cobb, Pupu etc	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
46	0			–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
47	*Add extra rows for additional consumer groups or price category codes as necessary*																							
48			**Standard consumer totals**	$5,275	$1,501	$213	$16	$138	$24	$2	$1	–	$3	$1	–	–	–	–	$115	$100	$12	–	–	–
49			**Non-standard consumer totals**	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
50			**Total for all consumers**	$5,275	$1,501	$213	$16	$138	$24	$2	$1	–	$3	$1	–	–	–	–	$115	$100	$12	–	–	–

51

52 ### 8(iii): Number of ICPs directly billed

53 **Number of directly billed ICPs at year end** 7

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
Information is also required on the number of ICPs that are included in each consumer group or price category code, and

sch ref

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

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sch ref	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	1	2	2HLFC	2LLFC	HLF	AnyDem31	AnyDem33	AnyDem34	AnyDem35	RCPD	kVAr	SD31	SN31	WD31	WN31	SD33	SN33
12–13				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	c/kWh	c/kWh	c/kWh	c/kWh
14																				
15	0S	Unmetered Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
16	0TBS	Temporary Builders Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
17	0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
18	1	15 kVA Capacity	Standard	35,909	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
19	2	20 - 150 kVA Capacity	Standard	–	121,542	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
20	2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
21	2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	–	–	–	37	–	–	–	–	–	–	–	–	–	–	–	–	–
22	HLF	High Load Factor, 15-150kVA Capacity	Standard	–	–	–	–	3,238	–	–	–	–	–	–	–	–	–	–	–	–
23	31	Between 150 and 3000kVA	Standard	–	–	–	–	–	2,410	–	–	–	1,452	–	4,360	1,809	3,007	1,295	–	–
	33	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	2,317	–	–	992	–	–	–	–	–	3,889	1,725
	34	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	41,443	–	17,377	172	–	–	–	–	–	–
	35	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	3,721	1,872	–	–	–	–	–	–	–
	6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	CB	Cobb River Hydro	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	0	0	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	0	0	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	0	0	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
24	0	0	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
25	*Add extra rows for additional consumer groups or price category codes as necessary*																			
26			**Standard consumer totals**	35,909	121,542	–	37	3,238	2,410	2,317	41,443	3,721	21,693	172	4,360	1,809	3,007	1,295	3,889	1,725
27			**Non-standard consumer totals**	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
28			**Total for all consumers**	35,909	121,542	–	37	3,238	2,410	2,317	41,443	3,721	21,693	172	4,360	1,809	3,007	1,295	3,889	1,725

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SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

This schedule requires the billed quantities and associated line charge revenues for each price category code used by the
Information is also required on the number of ICPs that are included in each consumer group or price category code, and

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

Row	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	1	2	2HLFC	2LLFC	HLF	AnyDem31	AnyDem33	AnyDem34	AnyDem35	RCPD	kVAr	SD31	SN31	WD31	WN31	SD33	SN33
35				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	c/kWh	c/kWh	c/kWh	c/kWh
37	0S	Unmetered Streetlamps	Standard						–	–	–	–	–	–	–	–	–	–	–	–
38	0TBS	Temporary Builders Supplies	Standard						–	–	–	–	–	–	–	–	–	–	–	–
39	0UNM	Unmetered Supplies	Standard						–	–	–	–	–	–	–	–	–	–	–	–
40	1	15 kVA Capacity	Standard	$1,966					–	–	–	–	–	–	–	–	–	–	–	–
41	2	20 - 150 kVA Capacity	Standard		$2,298				–	–	–	–	–	–	–	–	–	–	–	–
	2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard			–			–	–	–	–	–	–	–	–	–	–	–	–
	2LLFC	Domesitic low user, 40-150kVA Capacity	Standard				$2		–	–	–	–	–	–	–	–	–	–	–	–
	HLF	High Load Factor, 15-150kVA Capacity	Standard					$471	–	–	–	–	–	–	–	–	–	–	–	–
	31	Between 150 and 3000kVA	Standard	–	–	–	–	–	$109	–	–	–	$180	–	$19	$4	$24	$3	–	–
	33	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	$127	–	–	$123	–	–	–	–	–	$52	$12
	34	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	$2,390	–	$2,154	$16	–	–	–	–	–	–
	35	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	$204	$232	–	–	–	–	–	–	–
42	6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
43	6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
44	NDL/New Connections	New Connectionns, NDL	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
45	Embedded generators	Cobb, Pupu etc	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
46	0			–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
47	*Add extra rows for additional consumer groups or price category codes as necessary*																			
48			**Standard consumer totals**	$1,966	$2,298	–	$2	$471	$109	$127	$2,390	$204	$2,689	$16	$19	$4	$24	$3	$52	$12
49			**Non-standard consumer totals**	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
50			**Total for all consumers**	$1,966	$2,298	–	$2	$471	$109	$127	$2,390	$204	$2,689	$16	$19	$4	$24	$3	$52	$12

52 ### 8(iii): Number of ICPs directly billed

53 **Number of directly billed ICPs at year end** 7

Company Name
For Year Ended
Network / Sub-Network Name

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

This schedule requires the billed quantities and associated line charge revenues for each price category code used by the
Information is also required on the number of ICPs that are included in each consumer group or price category code, and

sch ref

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

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sch ref	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	WD33	WN33	SD34	SN34	WD34	WN34	SD35	SN35	WD35	WN35	6.1	6.2	NDL	NCA Admin G0	NCA Admin G1	NCA Admin G2	NCA Admin G3
13				c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	Annual	Annual	kVA=km	New connection application	New connection application	New connection application	New connection application
14																				
15	0S	Unmetered Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
16	0TBS	Temporary Builders Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
17	0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
18	1	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
19	2	20 - 150 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
20	2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
21	2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
22	HLF	High Load Factor, 15-150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
23	31	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	33	Between 150 and 3000kVA	Standard	2,092	843	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	34	Between 150 and 3000kVA	Standard	–	–	45,109	15,811	35,110	12,606	–	–	–	–	–	–	–	–	–	–	–
	35	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	5,164	2,256	4,432	1,975	–	–	–	–	–	–	–
	6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	CB	Cobb River Hydro	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	0	0	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	20,463	3	585	62	11
	0	0	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	0	0	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
24	0	0	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
25	*Add extra rows for additional consumer groups or price category codes as necessary*																			
26			**Standard consumer totals**	2,092	843	45,109	15,811	35,110	12,606	5,164	2,256	4,432	1,975	–	–	–	–	–	–	–
27			**Non-standard consumer totals**	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
28			**Total for all consumers**	2,092	843	45,109	15,811	35,110	12,606	5,164	2,256	4,432	1,975	–	–	–	–	–	–	–

29
30

Company Name
For Year Ended
Network / Sub-Network Name

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

This schedule requires the billed quantities and associated line charge revenues for each price category code used by the
Information is also required on the number of ICPs that are included in each consumer group or price category code, and

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

32
33

Row	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	WD33	WN33	SD34	SN34	WD34	WN34	SD35	SN35	WD35	WN35	6.1	6.2	NDL	NCA Admin G0	NCA Admin G1	NCA Admin G2	NCA Admin G3
34–35				c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	Annual	Annual	kVA=km	New connection application	New connection application	New connection application	New connection application
36																				
37	0S	Unmetered Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
38	0TBS	Temporary Builders Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
39	0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
40	1	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
41	2	20 - 150 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	HLF	High Load Factor, 15-150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	31	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	33	Between 150 and 3000kVA	Standard	$72	$6	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	34	Between 150 and 3000kVA	Standard	–	–	$609	$112	$1,211	$89	–	–	–	–	–	–	–	–	–	–	–
	35	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	$47	$13	$131	$11	–	–	–	–	–	–	–
42	6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	$2,030	–	–	–	–	–	–
43	6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	$593	–	–	–	–	–
44	NDL/New Connections	New Connectionns, NDL	Standard	–	–	–	–	–	–	–	–	–	–	–	–	$158	–	$146	$20	$5
45	Embedded generators	Cobb, Pupu etc	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
46	0			–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
47	*Add extra rows for additional consumer groups or price category codes as necessary*																			
48			**Standard consumer totals**	$72	$6	$609	$112	$1,211	$89	$47	$13	$131	$11	–	–	$158	–	$146	$20	$5
49			**Non-standard consumer totals**	–	–	–	–	–	–	–	–	–	–	$2,030	$593	–	–	–	–	–
50			**Total for all consumers**	$72	$6	$609	$112	$1,211	$89	$47	$13	$131	$11	$2,030	$593	$158	–	$146	$20	$5

51

52 ### 8(iii): Number of ICPs directly billed

53 **Number of directly billed ICPs at year end** 7

Network Tasman Limited
31 March 2017

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
Information is also required on the number of ICPs that are included in each consumer group or price category code, and

sch ref

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

9

10

11 *columns for*

sch ref	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	CB	Standard DG Part1A	Standard DG Part1	DG >10kw <100kW
12				Annual	Per application	Per application	Per application
15	0S	Unmetered Streetlamps	Standard	–	–	–	–
16	0TBS	Temporary Builders Supplies	Standard	–	–	–	–
17	0UNM	Unmetered Supplies	Standard	–	–	–	–
18	1	15 kVA Capacity	Standard	–	–	–	–
19	2	20 - 150 kVA Capacity	Standard	–	–	–	–
20	2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	–	–	–	–
21	2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	–	–	–	–
22	HLF	High Load Factor, 15-150kVA Capacity	Standard	–	–	–	–
23	31	Between 150 and 3000kVA	Standard	–	–	–	–
	33	Between 150 and 3000kVA	Standard	–	–	–	–
	34	Between 150 and 3000kVA	Standard	–	–	–	–
	35	Between 150 and 3000kVA	Standard	–	–	–	–
	6.1	> 3000,	Non-standard	–	–	–	–
	6.2	> 3000,	Non-standard	–	–	–	–
	CB	Cobb River Hydro	Non-standard	1,627,801	–	–	–
	0	0	[Select one]	–	132	3	1
	0	0	[Select one]	–	–	–	–
	0	0	[Select one]	–	–	–	–
24	0	0	[Select one]	–	–	–	–
25	*Add extra rows for additional consumer groups or price category codes as necessary*						
26			**Standard consumer totals**	–	–	–	–
27			**Non-standard consumer totals**	1,627,801	–	–	–
28			**Total for all consumers**	1,627,801	–	–	–

29

30

Network Tasman Limited
31 March 2017

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
Information is also required on the number of ICPs that are included in each consumer group or price category code, and

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

32
33

	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	CB	Standard DG Part1A	Standard DG Part1	DG >10kw <100kW
34				Annual	Per application	Per application	Per application
37	0S	Unmetered Streetlamps	Standard	–	–	–	–
38	0TBS	Temporary Builders Supplies	Standard	–	–	–	–
39	0UNM	Unmetered Supplies	Standard	–	–	–	–
40	1	15 kVA Capacity	Standard	–	–	–	–
41	2	20 - 150 kVA Capacity	Standard	–	–	–	–
	2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	–	–	–	–
	2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	–	–	–	–
	HLF	High Load Factor, 15-150kVA Capacity	Standard	–	–	–	–
	31	Between 150 and 3000kVA	Standard	–	–	–	–
	33	Between 150 and 3000kVA	Standard	–	–	–	–
	34	Between 150 and 3000kVA	Standard	–	–	–	–
	35	Between 150 and 3000kVA	Standard	–	–	–	–
42	6.1	> 3000,	Non-standard	–	–	–	–
43	6.2	> 3000,	Non-standard	–	–	–	–
44	NDL/New Connections	New Connectionns, NDL	Standard	–	$13	$1	$1
45	Embedded generators	Cobb, Pupu etc	Non-standard	$1,628	–	–	–
46	0			–	–	–	–
47	*Add extra rows for additional consumer groups or price category codes as necessary*						
48			**Standard consumer totals**	–	$13	$1	$1
49			**Non-standard consumer totals**	$1,628	–	–	–
50			**Total for all consumers**	$1,628	$13	$1	$1

51

52 **8(iii): Number of ICPs directly billed**

53 **Number of directly billed ICPs at year end** 7

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2017**
Network / Sub-network Name	

SCHEDULE 9a: ASSET REGISTER

This schedule requires a summary of the quantity of assets that make up the network, by asset category and asset class. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

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.	25,927	25,917	(10)	3
10	All	Overhead Line	Wood poles	No.	1,624	1,449	(175)	3
11	All	Overhead Line	Other pole types	No.	545	529	(16)	3
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	283	281	(2)	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.	101	101	–	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.	22	20	(2)	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	86	95	9	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	1,897	1,893	(4)	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	108	113	5	3
39	HV	Distribution Cable	Distribution UG PILC	km	137	135	(2)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	64	61	(3)	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.	1,259	1,266	7	3
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	235	184	(51)	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	32	96	64	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	3,809	3,815	6	3
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	662	678	16	3
48	HV	Distribution Transformer	Voltage regulators	No.	11	11	–	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	25	26	1	4
50	LV	LV Line	LV OH Conductor	km	507	504	(3)	3
51	LV	LV Cable	LV UG Cable	km	602	613	11	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	–	4
53	LV	Connections	OH/UG consumer service connections	No.	38,761	39,299	538	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	135	141	6	4
55	All	SCADA and communications	SCADA and communications equipment operating as a single syster	Lot	1	1	–	4
56	All	Capacitor Banks	Capacitors including controls	No	9	9	–	4
57	All	Load Control	Centralised plant	Lot	5	5	–	4
58	All	Load Control	Relays	No	–	–	–	4
59	All	Civils	Cable Tunnels	km	–	–	–	4

Company
For Year
Network / Sub-network

SCHEDULE 9b: ASSET AGE PROFILE

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

sch ref

8		Disclosure Year (year ended)	31 March 2017		Number of assets at disclosure year end by installation date																						
9	Voltage	Asset category	Asset class	Units	pre-1940	1940–1949	1950–1959	1960–1969	1970–1979	1980–1989	1990–1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
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	137	128	150	203
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	15	14	29	–
12	All	Overhead Line	Other pole types	No.	59	34	56	129	47	90	51	–	4	1	–	–	1	–	1	4	–	1	–	–	1	–	–
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	95	98	2	10	61	3	3	–	2	2	1	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	–	–	–	9	–	–
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	–	1	–	–	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	–	3	2	–	1	4	2	–	–	–	–	–	–	2	–	–	–	–	–	–	–	–	–
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	–	6	–	–	–	–	–	–	–	1	–	–	–	–	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	–	–	–	–	–	–	8	–	–
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	125	83	460	517	154	274	103	7	7	7	12	12	6	10	3	8	13	34	16	12	16	6	2
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
38	HV	Distribution Line	SWER conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	–	–	–	–	13	8	1	2	2	12	6	6	12	10	8	7	4	3	3	5	3	3
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	3	23	39	23	2	2	2	12	6	2	4	3	3	2	1	1	1	2	1	2
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	8	4	6	4
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	19	10	13	25
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	–	2	–	2	4	3	3	15	5	14	18	7	23	23	15	4	4	6	12	11
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	–	1	–	–	1	1	1	4	1	4	1	1	–	1	2	3	–	–	2	–
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	18	63	164	548	498	846	578	35	74	82	62	67	42	37	22	42	43	41	31	40	70	43	23
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	4	18	30	14
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	149	119	41	58	12	78	1	1	1	2	2	3	1	1	2	1	1	1	–	1	–
52	LV	LV Cable	LV UG Cable	km	–	–	3	7	87	124	105	8	15	28	27	25	19	18	17	14	18	15	12	9	9	11	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	464	460	557	442
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	3	–	2	2	17	43	–	13	–	12	2	8	16	–	–	–	–	–	–	6	–	–
56	All	SCADA and communications	SCADA and communications equipment operating as a single system	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	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–

Name	Network Tasman Limited
Ended	31 March 2017
Name	

SCHEDULE 9b: ASSET AGE PROFILE

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

sch ref

8 **Disclosure Year (year ended)** 31 March 2017

sch ref	Voltage	Asset category	Asset class	Units	2016	2017	No. with age unknow	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.	33	130	466	25,917	–	1
11	All	Overhead Line	Wood poles	No.	–	8	235	1,449	–	1
12	All	Overhead Line	Other pole types	No.	–	–	50	529	–	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	–	–	–	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	–	–	9	–	4
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	4
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	35	101	–	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.	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	–	6	–	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	–	5	–	113	–	2
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	1	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.	5	6	–	61	–	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.	5	7	848	1,266	–	2
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	5	8	184	–	2
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	4	69	96	–	2
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	16	2	328	3,815	–	3
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	13	9	10	678	–	3
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	6	11	–	2
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	1	26	–	2
51	LV	LV Line	LV OH Conductor	km	–	1	4	504	–	2
52	LV	LV Cable	LV UG Cable	km	3	14	13	613	–	2
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	–	–	–	2
54	LV	Connections	OH/UG consumer service connections	No.	447	538	#####	39,299	–	2
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	4	13	–	141	–	3
56	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	–	–	–	1	–	3
57	All	Capacitor Banks	Capacitors including controls	No	1	–	–	9	–	3
58	All	Load Control	Centralised plant	Lot	–	–	–	5	–	4
59	All	Load Control	Relays	No	–	–	–	–	–	4
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	4

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2017**
Network / Sub-network Name	

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref

9				
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	32
16	6.6kV to 11kV (inclusive—other than SWER)	1,879	238	2,117
17	Low voltage (< 1kV)	505	616	1,121
18	**Total circuit length (for supply)**	2,684	897	3,581
19				
20	Dedicated street lighting circuit length (km)	–	–	–
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			8
22				

23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**
24	Urban	189	7%
25	Rural	2,296	86%
26	Remote only	70	3%
27	Rugged only	121	5%
28	Remote and rugged	8	0%
29	Unallocated overhead lines	–	–
30	**Total overhead length**	2,684	100%
31			
32		**Circuit length (km)**	**(% of total circuit length)**
33	Length of circuit within 10km of coastline or geothermal areas (where known)	1,673	47%
34		**Circuit length (km)**	**(% of total overhead length)**
35	Overhead circuit requiring vegetation management	2,684	100%

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2017**

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	None		
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 2017**
Network / Sub-network Name	

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref

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	560	
12	Consumers greater than 20kVA	30	
13			
14			
15			
16	** include additional rows if needed*		
17	**Connections total**	590	
18			
19	**Distributed generation**		
20	Number of connections made in year	136	**connections**
21	Capacity of distributed generation installed in year	0.46	**MVA**
22	**9e(ii): System Demand**		
23			
24		**Demand at time of maximum coincident demand (MW)**	
25	**Maximum coincident system demand**		
26	GXP demand	106	
27	*plus* Distributed generation output at HV and above	32	
28	**Maximum coincident system demand**	138	
29	*less* Net transfers to (from) other EDBs at HV and above	18	
30	**Demand on system for supply to consumers' connection points**	120	
31	**Electricity volumes carried**	**Energy (GWh)**	
32	Electricity supplied from GXPs	608	
33	*less* Electricity exports to GXPs	91	
34	*plus* Electricity supplied from distributed generation	226	
35	*less* Net electricity supplied to (from) other EDBs	92	
36	**Electricity entering system for supply to consumers' connection points**	651	
37	*less* Total energy delivered to ICPs	614	
38	**Electricity losses (loss ratio)**	37	5.6%
39			
40	**Load factor**	0.62	
41	**9e(iii): Transformer Capacity**		
42		**(MVA)**	
43	Distribution transformer capacity (EDB owned)	401	
44	Distribution transformer capacity (Non-EDB owned, estimated)	44	
45	**Total distribution transformer capacity**	445	
46			
47	**Zone substation transformer capacity**	381	

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2017**
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

sch ref			
8	**10(i): Interruptions**		
9	**Interruptions by class**	**Number of interruptions**	
10	Class A (planned interruptions by Transpower)	1	
11	Class B (planned interruptions on the network)	173	
12	Class C (unplanned interruptions on the network)	163	
13	Class D (unplanned interruptions by Transpower)	2	
14	Class E (unplanned interruptions of EDB owned generation)	–	
15	Class F (unplanned interruptions of generation owned by others)	1	
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**	340	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	120	43
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)	0.03	8.5
26	Class B (planned interruptions on the network)	0.28	70.0
27	Class C (unplanned interruptions on the network)	1.29	115.7
28	Class D (unplanned interruptions by Transpower)	0.28	13.3
29	Class E (unplanned interruptions of EDB owned generation)	–	–
30	Class F (unplanned interruptions of generation owned by others)	0.28	21.4
31	Class G (unplanned interruptions caused by another disclosing entity)	–	–
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	–	–
34	**Total**	2.15	229.0
35			
36	**Normalised SAIFI and SAIDI**	**Normalised SAIFI**	**Normalised SAIDI**
37	Classes B & C (interruptions on the network)	1.56	185.8
38			
39	**Quality path normalised reliability limit**	**SAIFI reliability limit**	**SAIDI reliability limit**
40	SAIFI and SAIDI limits applicable to disclosure year*	1.68	157.8
41	** not applicable to exempt EDBs*		

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2017**
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

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

Cause	SAIFI	SAIDI
Lightning	0.01	3.7
Vegetation	0.03	3.2
Adverse weather	0.16	21.5
Adverse environment	0.23	19.5
Third party interference	0.26	29.1
Wildlife	0.09	6.6
Human error	0.06	0.4
Defective equipment	0.27	19.4
Cause unknown	0.19	12.3

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	–	–
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	0.22	62.5
Distribution cables (excluding LV)	0.04	4.3
Distribution other (excluding LV)	0.03	3.3

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.24	19.2
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	0.96	89.2
Distribution cables (excluding LV)	0.01	0.5
Distribution other (excluding LV)	0.08	6.9

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	4	281	1.42
Subtransmission cables	–	30	–
Subtransmission other	–		
Distribution lines (excluding LV)	134	1,895	7.07
Distribution cables (excluding LV)	2	250	0.80
Distribution other (excluding LV)	23		
Total	163		

Company Name	Network Tasman Limited
For Year Ended	31 March 2017

Schedule 14 Mandatory Explanatory Notes

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

2. This schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.1. Information provided in boxes 1 to 12 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

There have been no changes in classification.

Regulatory Profit (Schedule 3)

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

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

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

Box 2: Explanatory comment on regulatory profit

Other income includes Nelson Electricity Ltd management fee $49,000 and sundry income of $71,000.

Nelson Electricity Limited sales and the related transmission costs have been excluded from the regulatory profit. These amounts net to 0.

There have been no changes in classification.

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

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

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

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

Box 3: Explanatory comment on merger and acquisition expenditure

There were no mergers and acquisitions.

Value of the Regulatory Asset Base (Schedule 4)

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

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

There were the following changes in classification.

Category 2016	***Category 2017***	***$000***	***Explanation***
Distribution & LV Lines	Distribution & LV Cable	28	Cable expenditure was incorrectly classified as Line.
Distribution Switchgear	Zone Substations	28	Zone substation switchgear was incorrectly classified as Distribution Switchgear
Other Network Assets	Zone Substations	61	Zone substation metering was incorrectly classified as Other Network Assets
Other Network Assets	Distribution Switchgear	638	Voltage regulator were reclassified as Distribution Switchgear
Zone Substations	Distribution & LV Cable	242	Cable to zone substation reclassified
Zone Substations	Distribution Substations & Transformers	17	Distribution transformers were incorrectly categorised as zone substation switchgear
		1,014	

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

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

- Use of money interest received

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

- Non-deductible expenses

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

- RAB revaluation

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

- Line charge discounts
- Movement in provisions

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 $265,000 @28% = $74,000 and

Movement in provisions temporary difference -$451,000 @28% = $-126,000

Making temporary differences of $-52,000.

Related party transactions: disclosure of related party transactions (Schedule 5b)

10. In the box below, provide descriptions of related party transactions beyond those disclosed on Schedule 5b including identification and descriptions as to the nature of directly attributable costs disclosed under subclause 2.3.6(1)(b).

Box 7: Related party transactions

The management services fee of $49,000 is for providing engineering support to Nelson Electricity Limited.

On charge of Electricity Authority levies and other sundry charges to Nelson Electricity Limited $22,000.

Cost allocation (Schedule 5d)

11. 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 8: Cost allocation
Costs relating to unregulated businesses have been identified and excluded from the unallocated costs. Therefore all costs are directly attributable to the Electricity Distribution Services business.

Asset allocation (Schedule 5e)

12. 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 9: Commentary on asset allocation
The not directly attributable assets relate to assets constructed in 2004/2005. A calculation was done at the time to identify the share of costs that related to the EDB business. Only directly attributable assets have been commissioned since 2005. There has been no reclassification of assets.

Capital Expenditure for the Disclosure Year (Schedule 6a)

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

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

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

Box 10: 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)

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

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

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

14.3 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 11: 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 replace 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)

15. 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 12: Explanatory comment on variance in actual to forecast expenditure

Capital Expenditure

- Customer connection expenditure is above target due to greater than expected new commercial and industrial applications for supply.
- System growth is below target some projects have moved into the next year.
- Asset replacement and renewal is below target due to the recently purchased 66kV assets requiring less replacement and renewal expenditure than expected, and 2 of the major projects being delayed.
- Asset relocations are below target with 1 undergrounding project delayed until the 2017/18 year.
- Reliability, safety and environment – quality of supply is above target mostly due to the unbudgeted costs relating to adding a second transformer at the Stoke GXP to improve reliability.
- Other reliability, safety and environment is below target due to the transformer bunding projects being delayed until the next year.
- The expenditure on non-network assets is below target due to computer expenditure being delayed until the following year.

Operational Expenditure

- Service interruptions and emergencies costs are less than target thanks to less extraordinary events during the year.
- Vegetation management is below target with slightly less vegetation expenditure across the board than anticipated.
- Routine and corrective maintenance and inspection cost are less than target with a main underspend in substation and switchgear maintenance.
- Asset replacement and renewal expenditure is less than target due to a significant reduction in reactive maintenance for the year.
- Non-network expenditure is above target mainly due to additional costs associated with staff recruitment.

Information relating to revenues and quantities for the disclosure year

16. In the box below provide-

16.1 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

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

Box 13: Explanatory comment relating to revenue for the disclosure year
The variance between actual revenue and target was (0.6%). The variance is so small as to be treated as on target.

Network Reliability for the Disclosure Year (Schedule 10)

17. In the box below, comment on network reliability for the disclosure year, as disclosed in Schedule 10.

Network SAIDI minutes (average duration of supply interruptions per connected consumer, excluding Transpower planned and unplanned faults) were 186 minutes against a target of 115 minutes (181 minutes in 2015/16). Network reliability was affected by unplanned outages from the Kaikoura earthquake and an increase in planned outages from less live line work being undertaken for safety reasons. Network Tasman continues to focus on planned maintenance on the network and vegetation control to ensure improvement of the long-term safety and reliability of the electricity network. Overall, the Commerce Commission targets for reliability were not breached.

Insurance cover

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

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

18.2 In respect of any self insurance, the level of reserves, details of how reserves are managed and invested, and details of any reinsurance.

Box 15: Explanation of insurance cover
NTL had material damage cover for all zone sub-stations – buildings and associated equipment but does not insure the wider distribution network. In addition NTL has public liability, Directors and Officers insurance and failure to supply cover.

Amendments to previously disclosed information

19. 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:

    19.1 a description of each error; and

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

Box 16: Disclosure of amendment to previously disclosed information
There are no amendments to previously disclosed information.

Company Name	Network Tasman Limited
For Year Ended	31 March 2017

Schedule 14a Mandatory Explanatory Notes on Forecast Information

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 2.13% has been applied from the 2018 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 2.46% has been applied from the 2018 year.

Company Name	Network Tasman Limited
For Year Ended	31 March 2017

Schedule 15 Voluntary Explanatory Notes

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 9c. The difference is that the line “Maximum coincident system demand” includes Nelson Electricity Ltd (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 34kW/km.

Demand density	34

networktasman

Your consumer-owned electricity distributor

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Nelson, New Zealand

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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; and

In respect of related party costs and revenues recorded in accordance with subclauses 2.3.6(1) (when valued in accordance with clause 2.2.11(5)(h)(ii) of the Electricity Distribution Services Input Methodologies Determination 2010), 2.3.6(1)(f) and 2.3.7(2)(b), we certify that, having made all reasonable enquiry, including enquiries of our related parties, we are satisfied that to the best of our knowledge and belief the costs and revenues recorded for related party transactions reasonably reflect the price or prices that would have been paid or received had these transactions been at arm's-length.

Michael John MCCLISKIE

Anthony Page REILLY

28 July 2017

Independent Assurance Report

To the directors of Network Tasman Limited and to the Commerce Commission

The Auditor-General is the auditor of Network Tasman Limited (the company). The Auditor-General has appointed me, Ian Lothian, using the staff and resources of Audit New Zealand, to provide an opinion, on her behalf, on whether the information disclosed in schedules 1 to 4, 5a to 5g, 6a and 6b, 7, the system average interruption duration index ('SAIDI') and system average interruption frequency index ('SAIFI') information disclosed in Schedule 10 and the explanatory notes in boxes 1 to 12 in Schedule 14 ('the Disclosure Information') for the disclosure year ended 31 March 2017, have been prepared, in all material respects, in accordance with the Electricity Distribution Information Disclosure Determination 2012 (the 'Determination').

Directors' responsibility for the Disclosure Information

The directors of the company are responsible for preparation of the Disclosure Information in accordance with the Determination, and for such internal control as the directors determine is necessary to enable the preparation of the Disclosure Information that is free from material misstatement.

Our responsibility for the Disclosure Information

Our responsibility is to express an opinion on whether the Disclosure Information has been prepared, in all material respects, in accordance with the Determination.

Basis of 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 issued by the External Reporting Board and the Standard on Assurance Engagements 3100: Compliance Engagements issued by the External Reporting 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 in accordance with the Determination.

We have performed procedures to obtain evidence about the amounts and disclosures in the Disclosure Information. The procedures selected depend on our judgement, including the assessment of the risks of material misstatement of the Disclosure Information, whether due to fraud or error or non-compliance with the Determination. In making those risk assessments, we considered internal control relevant to the company's preparation of the Disclosure 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.

We also evaluated:

- the appropriateness of assumptions used and whether they have been consistently applied; and
- the reasonableness of the significant judgements made by the directors of 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 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.

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 nor do we guarantee complete accuracy of the Disclosure Information. Also we did not evaluate the security and controls over the electronic publication of the Disclosure Information.

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

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

We also complied with the independence requirements specified in the Determination.

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

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; and

- the Disclosure Information has been prepared, in all material respects, in accordance with the Determination.

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

Ian Lothian
Audit New Zealand
On behalf of the Auditor-General
Christchurch, New Zealand
28 July 2017