COUNTIES POWER

Information Disclosure prepared in accordance with the Electricity Distribution Information Disclosure Determination 2012

For the Year Ended 31 March 2018

Contents

1. Current Year Schedules

Company Name **Counties Power Limited**
For Year Ended **31 March 2018**

SCHEDULE 1: ANALYTICAL RATIOS

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

sch ref

1(i): Expenditure metrics

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)
9	**Operational expenditure**	22,887	309	110,668	3,985	37,213
10	Network	8,560	116	41,391	1,490	13,918
11	Non-network	14,327	193	69,277	2,495	23,295
12						
13	**Expenditure on assets**	42,943	580	207,646	7,477	69,823
14	Network	40,415	546	195,424	7,037	65,713
15	Non-network	2,528	34	12,222	440	4,110

1(ii): Revenue metrics

sch ref		Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
19	**Total consumer line charge revenue**	92,783	1,253
20	Standard consumer line charge revenue	100,110	1,185
21	Non-standard consumer line charge revenue	40,813	405,788

1(iii): Service intensity measures

sch ref			
25	Demand density	36	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
26	Volume density	174	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
27	Connection point density	13	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
28	Energy intensity	13,505	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*

1(iv): Composition of regulatory income

sch ref		($000)	% of revenue
32	Operational expenditure	12,890	24.61%
33	Pass-through and recoverable costs excluding financial incentives and wash-ups	13,746	26.24%
34	Total depreciation	7,899	15.08%
35	Total revaluations	2,661	5.08%
36	Regulatory tax allowance	2,931	5.59%
37	Regulatory profit/(loss) including financial incentives and wash-ups	17,577	33.55%
38	**Total regulatory income**	52,382	

1(v): Reliability

sch ref			
42	Interruption rate	22.38	*Interruptions per 100 circuit km*

Company Name	**Counties Power Limited**
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SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

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

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

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

sch ref

sch ref		CY-2	CY-1	Current Year CY
7	**2(i): Return on Investment**			
8		31 Mar 16	31 Mar 17	31 Mar 18
9	**ROI – comparable to a post tax WACC**	%	%	%
10	Reflecting all revenue earned	6.90%	7.73%	7.04%
11	Excluding revenue earned from financial incentives	6.90%	7.73%	7.04%
12	Excluding revenue earned from financial incentives and wash-ups	6.90%	7.73%	7.04%
13				
14	**Mid-point estimate of post tax WACC**	5.37%	4.77%	5.04%
15	25th percentile estimate	4.66%	4.05%	4.36%
16	75th percentile estimate	6.09%	5.48%	5.72%
17				
18				
19	**ROI – comparable to a vanilla WACC**			
20	Reflecting all revenue earned	7.55%	8.27%	7.63%
21	Excluding revenue earned from financial incentives	7.55%	8.27%	7.63%
22	Excluding revenue earned from financial incentives and wash-ups	7.55%	8.27%	7.63%
23				
24	**WACC rate used to set regulatory price path**			
25				
26	**Mid-point estimate of vanilla WACC**	6.02%	5.31%	5.60%
27	25th percentile estimate	5.30%	4.59%	4.92%
28	75th percentile estimate	6.74%	6.03%	6.29%
29				

sch ref				($000)	
30		**2(ii): Information Supporting the ROI**			
31					
32		Total opening RAB value	241,528		
33	*plus*	Opening deferred tax	(12,107)		
34		**Opening RIV**		229,421	
35					
36		**Line charge revenue**		52,255	
37					
38		Expenses cash outflow	26,636		
39	*add*	Assets commissioned	16,432		
40	*less*	Asset disposals	108		
41	*add*	Tax payments	1,170		
42	*less*	Other regulated income	127		
43		**Mid-year net cash outflows**		44,002	
44					
45		**Term credit spread differential allowance**		–	
46					
47		Total closing RAB value	253,205		
48	*less*	Adjustment resulting from asset allocation	593		
49	*less*	Lost and found assets adjustment	–		
50	*plus*	Closing deferred tax	(13,868)		
51		**Closing RIV**		238,745	
52					
53		**ROI – comparable to a vanilla WACC**			7.63%
54					
55		Leverage (%)			44%
56		Cost of debt assumption (%)			4.80%
57		Corporate tax rate (%)			28%
58					
59		**ROI – comparable to a post tax WACC**			7.04%
60					

sch ref							
61	**2(iii): Information Supporting the Monthly ROI**						
62							
63	**Opening RIV**						N/A
64							
65							
66		Line charge revenue	Expenses cash outflow	Assets commissioned	Asset disposals	Other regulated income	Monthly net cash outflows
67	April						–
68	May						–

Company Name	**Counties Power Limited**
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SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

This schedule requires information on the Return on Investment (ROI) for the EDB relative to the Commerce Commission's estimates of post tax WACC and vanilla WACC. EDBs must calculate their ROI based on a monthly basis if required by clause 2.3.3 of the ID Determination or if they elect to. If an EDB makes this election, information supporting this calculation must be provided in 2(iii).
EDBs must provide explanatory comment on their ROI in Schedule 14 (Mandatory Explanatory Notes).
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sch ref							
69	June						–
70	July						–
71	August						–
72	September						–
73	October						–
74	November						–
75	December						–
76	January						–
77	February						–
78	March						–
79	**Total**	–	–	–	–	–	–
80							
81	**Tax payments**						N/A
82							
83	**Term credit spread differential allowance**						N/A
84							
85	**Closing RIV**						N/A
86							
87							
88	**Monthly ROI – comparable to a vanilla WACC**						N/A
89							
90	**Monthly ROI – comparable to a post tax WACC**						N/A
91							
92	**2(iv): Year-End ROI Rates for Comparison Purposes**						
93							
94	**Year-end ROI – comparable to a vanilla WACC**						7.40%
95							
96	**Year-end ROI – comparable to a post tax WACC**						6.81%
97							
98	** these year-end ROI values are comparable to the ROI reported in pre 2012 disclosures by EDBs and do not represent the Commission's current view on ROI.*						
99							
100	**2(v): Financial Incentives and Wash-Ups**						
101							
102	Net recoverable costs allowed under incremental rolling incentive scheme					–	
103	Purchased assets – avoided transmission charge						
104	Energy efficiency and demand incentive allowance						
105	Quality incentive adjustment						
106	Other financial incentives						
107	**Financial incentives**						–
108							
109	**Impact of financial incentives on ROI**						–
110							
111	Input methodology claw-back						
112	Recoverable customised price-quality path costs						
113	Catastrophic event allowance						
114	Capex wash-up adjustment						
115	Transmission asset wash-up adjustment						
116	2013–2015 NPV wash-up allowance						
117	Reconsideration event allowance						
118	Other wash-ups						
119	**Wash-up costs**						–
120							
121	**Impact of wash-up costs on ROI**						–

Company Name	**Counties Power Limited**
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SCHEDULE 3: REPORT ON REGULATORY PROFIT

This schedule requires information on the calculation of regulatory profit for the EDB for the disclosure year. All EDBs must complete all sections and provide explanatory comment on their regulatory profit in Schedule 14 (Mandatory Explanatory Notes).
This information is part of audited disclosure information (as defined in section 1.4 of 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		52,255
10	*plus*	Gains / (losses) on asset disposals		(79)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)		206
12				
13		**Total regulatory income**		52,382
14		**Expenses**		
15	*less*	Operational expenditure		12,890
16				
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups		13,746
18				
19		**Operating surplus / (deficit)**		25,746
20				
21	*less*	Total depreciation		7,899
22				
23	*plus*	Total revaluations		2,661
24				
25		**Regulatory profit / (loss) before tax**		20,507
26				
27	*less*	Term credit spread differential allowance		–
28				
29	*less*	Regulatory tax allowance		2,931
30				
31		**Regulatory profit/(loss) including financial incentives and wash-ups**		17,577
32				
33		**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	**($000)**	
34		**Pass through costs**		
35		Rates	661	
36		Commerce Act levies	100	
37		Industry levies	106	
38		CPP specified pass through costs		
39		**Recoverable costs excluding financial incentives and wash-ups**		
40		Electricity lines service charge payable to Transpower	11,940	
41		Transpower new investment contract charges	301	
42		System operator services		
43		Distributed generation allowance	637	
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**		13,746
47				

Company Name	**Counties Power Limited**
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SCHEDULE 3: REPORT ON REGULATORY PROFIT

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

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sch ref				
48	**3(iii): Incremental Rolling Incentive Scheme**		**($000)**	
49			**CY-1**	**CY**
50			**31 Mar 17**	**31 Mar 18**
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 13		
58	CY-4	31 Mar 14		
59	CY-3	31 Mar 15		
60	CY-2	31 Mar 16		
61	CY-1	31 Mar 17		
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	**Counties Power Limited**
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SCHEDULE 4: REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)

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

sch ref

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

	RAB	RAB	RAB	RAB	RAB
for year ended	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**
	($000)	**($000)**	**($000)**	**($000)**	**($000)**
Total opening RAB value	200,786	210,305	228,249	231,077	241,528
less **Total depreciation**	6,608	7,132	7,623	7,690	7,899
plus **Total revaluations**	3,069	176	1,337	4,997	2,661
plus **Assets commissioned**	13,490	25,260	9,361	13,336	16,432
less **Asset disposals**	433	360	247	193	108
plus **Lost and found assets adjustment**					–
plus **Adjustment resulting from asset allocation**					593
Total closing RAB value	210,305	228,249	231,077	241,528	253,205

4(ii): Unallocated Regulatory Asset Base

	Unallocated RAB *		RAB	
	($000)	**($000)**	**($000)**	**($000)**
Total opening RAB value		242,121		241,528
less				
Total depreciation		7,899		7,899
plus				
Total revaluations		2,661		2,661
plus				
Assets commissioned (other than below)	5,710		5,710	
Assets acquired from a regulated supplier				
Assets acquired from a related party	10,722		10,722	
Assets commissioned		16,432		16,432
less				
Asset disposals (other than below)	108		108	
Asset disposals to a regulated supplier				
Asset disposals to a related party				
Asset disposals		108		108
plus **Lost and found assets adjustment**				
plus **Adjustment resulting from asset allocation**				593
Total closing RAB value		253,205		253,205

** 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.*

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

CPI_4	1,011
CPI_4^{-4}	1,000
Revaluation rate (%)	1.10%

	Unallocated RAB *		RAB	
	($000)	**($000)**	**($000)**	**($000)**
Total opening RAB value	242,121		241,528	
less Opening value of fully depreciated, disposed and lost assets	241		(352)	
Total opening RAB value subject to revaluation	241,880		241,880	
Total revaluations		2,661		2,661

4(iv): Roll Forward of Works Under Construction

	Unallocated works under construction		Allocated works under construction	
Works under construction—preceding disclosure year		1,470		1,467
plus Capital expenditure	16,233		16,000	
less Assets commissioned	16,432		16,432	
plus Adjustment resulting from asset allocation			236	
Works under construction - current disclosure year		1,271		1,271
Highest rate of capitalised finance applied				

Company Name **Counties Power Limited**
For Year Ended **31 March 2018**

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	7,249		7,249	
80	Depreciation - no standard life assets	650		650	
81	Depreciation - modified life assets				
82	Depreciation - alternative depreciation in accordance with CPP				
83	**Total depreciation**		7,899		7,899

85 **4(vi): Disclosure of Changes to Depreciation Profiles** **($000 unless otherwise specified)**

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

95 ** include additional rows if needed*

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

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

sch ref			Subtransmission lines	Subtransmission cables	Zone substations	Distribution and LV lines	Distribution and LV cables	Distribution substations and transformers	Distribution switchgear	Other network assets	Non-network assets	Total
99		**Total opening RAB value**	17,077	231	21,189	90,130	37,936	39,415	10,075	4,936	20,539	241,528
100	*less*	Total depreciation	426	8	633	2,330	1,285	1,405	699	369	745	7,899
101	*plus*	Total revaluations	188	3	233	991	417	432	111	54	231	2,661
102	*plus*	Assets commissioned	374	–	905	5,981	2,426	2,418	1,433	1,470	1,424	16,432
103	*less*	Asset disposals	–	–	–	–	–	107	–	–	2	108
104	*plus*	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
105	*plus*	Adjustment resulting from asset allocation	–	–	–	–	–	–	–	–	593	593
106	*plus*	Asset category transfers										–
107		**Total closing RAB value**	17,213	225	21,694	94,773	39,494	40,755	10,919	6,092	22,041	253,205
108												
109		**Asset Life**										
110		Weighted average remaining asset life	45.9	28.3	35.7	43.5	33.6	32.2	24.0	11.3	13.5	(years)
111		Weighted average expected total asset life	59.0	45.0	47.4	59.3	49.2	45.0	37.0	17.1	20.8	(years)

Company Name	**Counties Power Limited**
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SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

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

sch ref				($000)	
7	**5a(i): Regulatory Tax Allowance**			($000)	
8		**Regulatory profit / (loss) before tax**		20,507	
9					
10	*plus*	Income not included in regulatory profit / (loss) before tax but taxable			*
11		Expenditure or loss in regulatory profit / (loss) before tax but not deductible	39		*
12		Amortisation of initial differences in asset values	2,681		
13		Amortisation of revaluations	734		
14				3,454	
15					
16	*less*	Total revaluations	2,661		
17		Income included in regulatory profit / (loss) before tax but not taxable			*
18		Discretionary discounts and customer rebates	6,100		
19		Expenditure or loss deductible but not in regulatory profit / (loss) before tax			*
20		Notional deductible interest	4,733		
21				13,494	
22					
23		**Regulatory taxable income**		10,467	
24					
25	*less*	Utilised tax losses			
26		Regulatory net taxable income		10,467	
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**		2,931	
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	77,303		
37	*less*	Amortisation of initial differences in asset values	2,681		
38	*plus*	Adjustment for unamortised initial differences in assets acquired			
39	*less*	Adjustment for unamortised initial differences in assets disposed	15		
40		Closing unamortised initial differences in asset values		74,608	
41					
42		Opening weighted average remaining useful life of relevant assets (years)		29	
43					

Company Name	**Counties Power Limited**
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SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

This schedule requires information on the calculation of the regulatory tax allowance. This information is used to calculate regulatory profit/loss in Schedule 3 (regulatory profit). EDBs must provide explanatory commentary on the information disclosed in this schedule, in Schedule 14 (Mandatory Explanatory Notes).
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sch ref				
44		**5a(iv): Amortisation of Revaluations**		**($000)**
45				
46		Opening sum of RAB values without revaluations	222,272	
47				
48		Adjusted depreciation	7,166	
49		Total depreciation	7,899	
50		Amortisation of revaluations		734
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**	(12,107)	
61				
62	*plus*	Tax effect of adjusted depreciation	2,006	
63				
64	*less*	Tax effect of tax depreciation	3,038	
65				
66	*plus*	Tax effect of other temporary differences*	17	
67				
68	*less*	Tax effect of amortisation of initial differences in asset values	751	
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	(4)	
73				
74	*plus*	Deferred tax cost allocation adjustment	–	
75				
76		**Closing deferred tax**		(13,868)
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**	103,479	
84	*less*	Tax depreciation	10,851	
85	*plus*	Regulatory tax asset value of assets commissioned	16,432	
86	*less*	Regulatory tax asset value of asset disposals	89	
87	*plus*	Lost and found assets adjustment		
88	*plus*	Adjustment resulting from asset allocation	593	
89	*plus*	Other adjustments to the RAB tax value		
90		**Closing sum of regulatory tax asset values**		109,563

Company Name	**Counties Power Limited**
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SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

This schedule provides information on the valuation of related party transactions, in accordance with 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

7 **5b(i): Summary—Related Party Transactions**

sch ref		($000)
8	Total regulatory income	
9	Operational expenditure	2,865
10	Capital expenditure	10,722
11	Market value of asset disposals	
12	Other related party transactions	

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

14	Name of related party	Related party relationship
15	Counties Power Limited - Field Operations	Part of Counties Power Limited run as a separate department and accounted for separately
16		Performs faults, proactive maintenance and construction services on the Network asset.
17		
18		
19		

20 ** include additional rows if needed*

21 **5b(iii): Related Party Transactions**

22	Name of related party	Related party transaction type	Description of transaction	Value of transaction ($000)	Basis for determining value
23	Counties Power Limited - Field Operations	Opex	Faults and Reactive	1,523	ID clause 2.3.6(1)(b)
24	Counties Power Limited - Field Operations	Opex	Tree Maintenance	509	ID clause 2.3.6(1)(b)
25	Counties Power Limited - Field Operations	Opex	Transformer Maintenance	190	ID clause 2.3.6(1)(b)
26	Counties Power Limited - Field Operations	Opex	Distribution OH Maintenance	180	ID clause 2.3.6(1)(b)
27	Counties Power Limited - Field Operations	Opex	Substation Maintenance	174	ID clause 2.3.6(1)(b)
28	Counties Power Limited - Field Operations	Opex	Distribution UG Maintenance	93	ID clause 2.3.6(1)(b)
29	Counties Power Limited - Field Operations	Opex	Subtransmission Maintenance	88	ID clause 2.3.6(1)(b)
30	Counties Power Limited - Field Operations	Opex	Switchgear	108	ID clause 2.3.6(1)(b)
31	Counties Power Limited - Field Operations	Capex	Subtransmision Capital	136	IM clause 2.2.11(5)(g)
32	Counties Power Limited - Field Operations	Capex	Construction Lines & Cable	3,229	IM clause 2.2.11(5)(g)
33	Counties Power Limited - Field Operations	Capex	Construction Low Voltage Reticulation	5,464	IM clause 2.2.11(5)(g)
34	Counties Power Limited - Field Operations	Capex	Substations	241	IM clause 2.2.11(5)(g)
35	Counties Power Limited - Field Operations	Capex	Transformers	1,228	IM clause 2.2.11(5)(g)
36	Counties Power Limited - Field Operations	Capex	System Automation & Comms	42	IM clause 2.2.11(5)(g)
37	Counties Power Limited - Field Operations	Capex	Switchgear	382	IM clause 2.2.11(5)(g)

38 ** include additional rows if needed*

Company Name	**Counties Power Limited**
For Year Ended	**31 March 2018**

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
10										
11	Counties Power Limited does not have any qualifying debt									
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	**Counties Power Limited**
For Year Ended	**31 March 2018**

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref

sch ref	5d(i): Operating Cost Allocations	Arm's length deduction	Value allocated ($000s) Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
10	**Service interruptions and emergencies**					
11	Directly attributable		1,956			
12	Not directly attributable				–	
13	**Total attributable to regulated service**		1,956			
14	**Vegetation management**					
15	Directly attributable		957			
16	Not directly attributable				–	
17	**Total attributable to regulated service**		957			
18	**Routine and corrective maintenance and inspection**					
19	Directly attributable		1,241			
20	Not directly attributable				–	
21	**Total attributable to regulated service**		1,241			
22	**Asset replacement and renewal**					
23	Directly attributable		667			
24	Not directly attributable				–	
25	**Total attributable to regulated service**		667			
26	**System operations and network support**					
27	Directly attributable		2,779			
28	Not directly attributable				–	
29	**Total attributable to regulated service**		2,779			
30	**Business support**					
31	Directly attributable		5,290			
32	Not directly attributable				–	
33	**Total attributable to regulated service**		5,290			
34						
35	**Operating costs directly attributable**		12,890			
36	**Operating costs not directly attributable**	–	–	–	–	–
37	**Operational expenditure**		12,890			

5d(ii): Other Cost Allocations

sch ref		($000)
40	**Pass through and recoverable costs**	
41	**Pass through costs**	
42	Directly attributable	813
43	Not directly attributable	28
44	**Total attributable to regulated service**	841
45	**Recoverable costs**	
46	Directly attributable	12,879
47	Not directly attributable	
48	**Total attributable to regulated service**	12,879

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

sch ref				($000) CY-1	Current Year (CY)
52	**Change in cost allocation 1**				
53	Cost category	Business Support	Original allocation	5,488	5,290
54	Original allocator or line items	ACAM	New allocation	5,488	5,290
55	New allocator or line items	Directly Attributable	Difference	–	–
57	Rationale for change	Only costs directly attributable to the lines business have been included above. The amounts included for Business Support are consistent with those reported using ACAM methodology.			
61	**Change in cost allocation 2**				
62	Cost category		Original allocation		
63	Original allocator or line items		New allocation		
64	New allocator or line items		Difference	–	–
66	Rationale for change				
70	**Change in cost allocation 3**				
71	Cost category		Original allocation		
72	Original allocator or line items		New allocation		
73	New allocator or line items		Difference	–	–
75	Rationale for change				

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

79 *† include additional rows if needed*

Company Name	**Counties Power Limited**
For Year Ended	**31 March 2018**

SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

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

sch ref

7 5e(i): Regulated Service Asset Values

sch ref		Value allocated ($000s) Electricity distribution services
8		
9		
10	**Subtransmission lines**	
11	Directly attributable	17,213
12	Not directly attributable	
13	**Total attributable to regulated service**	17,213
14	**Subtransmission cables**	
15	Directly attributable	225
16	Not directly attributable	
17	**Total attributable to regulated service**	225
18	**Zone substations**	
19	Directly attributable	21,694
20	Not directly attributable	
21	**Total attributable to regulated service**	21,694
22	**Distribution and LV lines**	
23	Directly attributable	94,773
24	Not directly attributable	
25	**Total attributable to regulated service**	94,773
26	**Distribution and LV cables**	
27	Directly attributable	39,494
28	Not directly attributable	
29	**Total attributable to regulated service**	39,494
30	**Distribution substations and transformers**	
31	Directly attributable	40,755
32	Not directly attributable	
33	**Total attributable to regulated service**	40,755
34	**Distribution switchgear**	
35	Directly attributable	10,919
36	Not directly attributable	
37	**Total attributable to regulated service**	10,919
38	**Other network assets**	
39	Directly attributable	6,092
40	Not directly attributable	
41	**Total attributable to regulated service**	6,092
42	**Non-network assets**	
43	Directly attributable	22,041
44	Not directly attributable	
45	**Total attributable to regulated service**	22,041
46		
47	**Regulated service asset value directly attributable**	253,205
48	**Regulated service asset value not directly attributable**	–
49	**Total closing RAB value**	253,205
50		

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

sch ref				($000) CY-1	($000) Current Year (CY)
52					
53	**Change in asset value allocation 1**				
54	Asset category	Non-network assets	Original allocation	20,539	21,448
55	Original allocator or line items	ACAM	New allocation	21,132	22,041
56	New allocator or line items	Directly Attributable	Difference	(593)	(593)
57					
58	Rationale for change	A review of Non-network assets has determined that the underlying assets are fully attributable to the electricity distribution services. The asset allocations historically treated as not directly attributable are of such a low magnitude they are not considered avoidable.			
59					
60					
61					
62	**Change in asset value allocation 2**				
63	Asset category		Original allocation		
64	Original allocator or line items		New allocation		
65	New allocator or line items		Difference	–	–
66					
67	Rationale for change				
68					
69					
70					
71	**Change in asset value allocation 3**				
72	Asset category		Original allocation		
73	Original allocator or line items		New allocation		
74	New allocator or line items		Difference	–	–
75					
76	Rationale for change				
77					
78					

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

80 *† include additional rows if needed*

Company Name	**Counties Power Limited**
For Year Ended	**31 March 2018**

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		12,172
9		System growth		2,348
10		Asset replacement and renewal		6,956
11		Asset relocations		50
12		Reliability, safety and environment:		
13		Quality of supply	109	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	1,126	
16		**Total reliability, safety and environment**		1,235
17		**Expenditure on network assets**		22,762
18		Expenditure on non-network assets		1,424
19				
20		**Expenditure on assets**		24,185
21	*plus*	Cost of financing		
22	*less*	Value of capital contributions		8,185
23	*plus*	Value of vested assets		
24				
25		**Capital expenditure**		16,000
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		749
29		Research and development		
30		**6a(iii): Consumer Connection**		
31		*Consumer types defined by EDB**	**($000)**	**($000)**
32		Urban residential	8,521	
33		Urban commercial	974	
34		Rural residential	1,826	
35		Rural commercial	852	
36				
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		12,172
39				
40	*less*	Capital contributions funding consumer connection expenditure	8,185	
41		**Consumer connection less capital contributions**		3,987
42		**6a(iv): System Growth and Asset Replacement and Renewal**		**Asset Replacement and**
43			**System Growth**	**Renewal**
44			**($000)**	**($000)**
45		Subtransmission	–	92
46		Zone substations	114	517
47		Distribution and LV lines	1,691	3,562
48		Distribution and LV cables	222	1,386
49		Distribution substations and transformers	43	464
50		Distribution switchgear	260	746
51		Other network assets	17	189
52		**System growth and asset replacement and renewal expenditure**	2,348	6,956
53	*less*	Capital contributions funding system growth and asset replacement and renewal		
54		**System growth and asset replacement and renewal less capital contributions**	2,348	6,956
55				
56		**6a(v): Asset Relocations**		
57		*Project or programme**	**($000)**	**($000)**
58		Asset Relocations	50	
59				
60				
61				
62				
63		** include additional rows if needed*		
64		All other projects or programmes - asset relocations		
65		**Asset relocations expenditure**		50
66	*less*	Capital contributions funding asset relocations		
67		**Asset relocations less capital contributions**		50

Company Name	**Counties Power Limited**
For Year Ended	**31 March 2018**

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

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

sch ref				
68				
69	**6a(vi): Quality of Supply**			
70		*Project or programme**	**($000)**	**($000)**
71		Voltage compliance	109	
72				
73				
74				
75				
76		** include additional rows if needed*		
77		All other projects programmes - quality of supply		
78	**Quality of supply expenditure**			109
79	*less*	Capital contributions funding quality of supply		
80	**Quality of supply less capital contributions**			109
81	**6a(vii): Legislative and Regulatory**			
82		*Project or programme**	**($000)**	**($000)**
83				
84				
85				
86				
87				
88		** include additional rows if needed*		
89		All other projects or programmes - legislative and regulatory		
90	**Legislative and regulatory expenditure**			–
91	*less*	Capital contributions funding legislative and regulatory		
92	**Legislative and regulatory less capital contributions**			–
93	**6a(viii): Other Reliability, Safety and Environment**			
94		*Project or programme**	**($000)**	**($000)**
95		Energy storage trial	680	
96		Improve reliability of Whangarata and Hitchen Road feeders (front end sections)	69	
97		Te Toro feeder upgrade (Eastern King Street)	185	
98		Pukekohe - Tuakau 110kV line corridor visual mitigation measures	11	
99		DFA and Fault Indicators	180	
100		** include additional rows if needed*		
101		All other projects or programmes - other reliability, safety and environment		
102	**Other reliability, safety and environment expenditure**			1,126
103	*less*	Capital contributions funding other reliability, safety and environment		
104	**Other reliability, safety and environment less capital contributions**			1,126
105				
106	**6a(ix): Non-Network Assets**			
107	**Routine expenditure**			
108		*Project or programme**	**($000)**	**($000)**
109		Replacement - Vehicles, Plant, Tools, Computing and Office	1,424	
110				
111				
112				
113				
114		** include additional rows if needed*		
115		All other projects or programmes - routine expenditure		
116	**Routine expenditure**			1,424
117	**Atypical expenditure**			
118		*Project or programme**	**($000)**	**($000)**
119		Nil		
120				
121				
122				
123				
124		** include additional rows if needed*		
125		All other projects or programmes - atypical expenditure		
126	**Atypical expenditure**			–
127				
128	**Expenditure on non-network assets**			1,424

Company Name	**Counties Power Limited**
For Year Ended	**31 March 2018**

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	1,956	
9	Vegetation management	957	
10	Routine and corrective maintenance and inspection	1,241	
11	Asset replacement and renewal	667	
12	**Network opex**		4,821
13	System operations and network support	2,779	
14	Business support	5,290	
15	**Non-network opex**		8,069
16			
17	**Operational expenditure**		12,890
18	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
19	Energy efficiency and demand side management, reduction of energy losses		
20	Direct billing*		
21	Research and development		
22	Insurance		272
23	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**Counties Power Limited**
For Year Ended	**31 March 2018**

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	51,698	52,255	1%
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	7,700	12,172	58%
11	System growth	3,790	2,348	(38%)
12	Asset replacement and renewal	7,460	6,956	(7%)
13	Asset relocations	300	50	(83%)
14	Reliability, safety and environment:			
15	Quality of supply	350	109	(69%)
16	Legislative and regulatory	60	–	(100%)
17	Other reliability, safety and environment	2,215	1,126	(49%)
18	**Total reliability, safety and environment**	2,625	1,235	(53%)
19	**Expenditure on network assets**	21,875	22,762	4%
20	Expenditure on non-network assets	2,995	1,424	(52%)
21	Expenditure on assets	24,870	24,185	(3%)
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	1,700	1,956	15%
24	Vegetation management	1,000	957	(4%)
25	Routine and corrective maintenance and inspection	1,000	1,241	24%
26	Asset replacement and renewal	806	667	(17%)
27	**Network opex**	4,506	4,821	7%
28	System operations and network support	2,836	2,779	(2%)
29	Business support	5,617	5,290	(6%)
30	**Non-network opex**	8,453	8,069	(5%)
31	**Operational expenditure**	12,959	12,890	(1%)
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	300	749	150%
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		–	–
39	Direct billing		–	–
40	Research and development		–	–
41	Insurance	238	272	14%
42				
43	*1 From the nominal dollar target revenue for the disclosure year disclosed under clause 2.4.3(3) of this determination*			
44	*2 From the CY+1 nominal dollar expenditure forecasts disclosed in accordance with clause 2.6.6 for the forecast period starting at the beginning of the disclosure year (the second to last disclosure of Schedules 11a and 11b)*			

Company Name	Counties Power Limited
For Year Ended	31 March 2018
Network / Sub-Network Name	

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

8(i): Billed Quantities by Price Component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)
Business	Commercial	Standard	7,336	102,564
3 Rate	Commercial	Standard	122	9,373
Standard Domestic	Residential	Standard	20,410	189,262
Low User Domestic	Residential	Standard	12,965	72,871
Prepaid Domestic	Residential	Standard	687	3,546
Time Of Use	Commercial	Standard	160	113,651
Streetlights	Commercial	Standard	19	2,336
Major Customer A	Commercial	Non-standard	4	40,775
Major Customer B	Commercial	Non-standard	1	15,654
Major Customer C	Commercial	Non-standard	2	13,169
Add extra rows for additional consumer groups or price category codes as necessary				
		Standard consumer totals	41,697	493,603
		Non-standard consumer totals	7	69,598
		Total for all consumers	41,704	563,201

Billed quantities by price component

Price component	00700-1100	1700-2200	2400-0700	Anytime	Day	Econo	M/W Light	Night	Off Peak	Priority Econo	Peak Saver
Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh
Business	–	–	–	93,782	545	7,160	–	772	–	–	138
3 Rate	–	–	–	–	–	–	–	2,373	4,294	–	–
Standard Domestic	–	–	–	#######	–	47,048	–	–	–	–	369
Low User Domestic	–	–	–	51,844	–	20,629	–	–	–	–	212
Prepaid Domestic	–	–	–	–	–	–	–	–	–	–	–
Time Of Use	23,556	16,716	25,370	465	–	–	–	436	46,579	–	–
Streetlights	–	–	–	–	–	–	251	–	–	–	–
Major Customer A	–	–	–	–	–	–	–	–	–	–	–
Major Customer B	–	–	–	–	–	–	–	–	–	–	–
Major Customer C	–	–	–	–	–	–	–	–	–	–	–
Standard consumer totals	23,556	16,716	25,370	#######	545	74,838	251	3,581	50,872	–	719
Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–	–
Total for all consumers	23,556	16,716	25,370	#######	545	74,838	251	3,581	50,872	–	719

Price component	Prepay	Summer Peak	Streetlight	Thrifty Night	Winter Peak	Annual Contract	Export	Demand	Reactive	Supply	Transformer
Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kVA	kVArh	Day	Day
Business	–	–	–	166	–	–	40	–	72	2,600	–
3 Rate	–	1,561	–	–	1,145	–	(109)	–	–	44	–
Standard Domestic	–	–	–	457	–	–	769	–	–	7,450	–
Low User Domestic	–	–	–	186	–	–	316	–	–	4,799	–
Prepaid Domestic	3,546	–	–	–	–	–	–	–	–	–	–
Time Of Use	–	294	–	–	235	–	–	370	6,828	–	107
Streetlights	–	–	2,085	–	–	–	–	–	–	–	–
Major Customer A	–	–	–	–	–	40,775	–	–	–	–	–
Major Customer B	–	–	–	–	–	15,654	–	–	–	–	–
Major Customer C	–	–	–	–	–	13,169	–	–	–	–	–
Standard consumer totals	3,546	1,855	2,085	809	1,380	–	1,016	370	6,900	14,893	107
Non-standard consumer totals	–	–	–	–	–	69,598	–	–	–	–	–
Total for all consumers	3,546	1,855	2,085	809	1,380	69,598	1,016	370	6,900	14,893	107

8(ii): 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)
Business	Commercial	Standard	$11,873	$909	$11,873	
3 Rate	Commercial	Standard	$750	$57	$750	
Standard Domestic	Residential	Standard	$19,929	$1,526	$19,929	
Low User Domestic	Residential	Standard	$8,037	$615	$8,037	
Prepaid Domestic	Residential	Standard	$354	$27	$354	
Time Of Use	Commercial	Standard	$8,022	$614	$8,022	
Streetlights	Commercial	Standard	$450	$34	$450	
Major Customer A	Industrial	Non-standard	$1,577	$121	$1,577	
Major Customer B	Industrial	Non-standard	$766	$59	$766	
Major Customer C	Industrial	Non-standard	$497	$38	$497	
Add extra rows for additional consumer groups or price category codes as necessary						
		Standard consumer totals	$49,415	$3,783	$49,415	–
		Non-standard consumer totals	$2,841	$217	$2,841	–
		Total for all consumers	$52,255	$4,000	$52,255	–

Line charge revenues ($000) by price component

rice component	0700-1100	1700-2200	2400-0700	Anytime	Day	Econo	M/W Light	Night	Off Peak	Priority Econo	Peak Saver
Rate (eg, $ per day, $ per kWh, etc.)	$ per kWh	$ per kWh	$ per kWh	$ per kWh	$ per kWh	$ per kWh	$ per kWh	$ per kWh	$ per kWh	$ per kWh	$ per kWh
Business	–	–	–	9,123	26	349	–	76	–	–	7
3 Rate	–	–	–	–	–	–	–	58	314	–	–
Standard Domestic	–	–	–	13,185	–	2,194	–	–	–	–	17
Low User Domestic	–	–	–	5,938	–	1,401	–	–	–	–	14
Prepaid Domestic	–	–	–	–	–	–	–	–	–	–	–
Time Of Use	973	1,063	297	45	–	–	–	11	885	–	–
Streetlights	–	–	–	–	–	–	25	–	–	–	–
Major Customer A	–	–	–	–	–	–	–	–	–	–	–
Major Customer B	–	–	–	–	–	–	–	–	–	–	–
Major Customer C	–	–	–	–	–	–	–	–	–	–	–
Standard consumer totals	973	1,063	297	28,290	26	3,943	25	145	1,199	–	38
Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–	–
Total for all consumers	973	1,063	297	28,290	26	3,943	25	145	1,199	–	38

rice component	Prepay	Summer Peak	Streetlight	Thrifty Night	Winter Peak	Annual Contract	Export	Demand	Reactive	Supply	Transformer
Rate (eg, $ per day, $ per kWh, etc.)	$ per kWh	$ per kWh	$ per kWh	$ per kWh	$ per kWh	$ per kWh	$/kWh	$ per kVA	$ per kVArh	$ per Day	$ per Day
Business	–	–	–	8	–	–	0	–	4	2,280	–
3 Rate	–	157	–	–	183	–	(1)	–	–	39	–
Standard Domestic	–	–	–	21	–	–	7	–	–	4,504	–
Low User Domestic	–	–	–	13	–	–	3	–	–	669	–
Prepaid Domestic	354	–	–	–	–	–	–	–	–	–	–
Time Of Use	–	28	–	–	40	–	–	3,591	357	–	732
Streetlights	–	–	424	–	–	–	–	–	–	–	–
Major Customer A	–	–	–	–	–	1,577	–	–	–	–	–
Major Customer B	–	–	–	–	–	766	–	–	–	–	–
Major Customer C	–	–	–	–	–	497	–	–	–	–	–
Standard consumer totals	354	186	424	42	223	–	10	3,591	360	7,491	732
Non-standard consumer totals	–	–	–	–	–	2,841	–	–	–	–	–
Total for all consumers	354	186	424	42	223	2,841	10	3,591	360	7,491	732

8(iii): Number of ICPs directly billed

Check: OK

Number of directly billed ICPs at year end	7

Company Name	**Counties Power Limited**
For Year Ended	**31 March 2018**
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.	25,907	26,097	190	3
10	All	Overhead Line	Wood poles	No.	1,082	1,881	799	3
11	All	Overhead Line	Other pole types	No.	6	5	(1)	3
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	87	87	0	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	72	72	(0)	4
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	2	2	–	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	N/A
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	N/A
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	N/A
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	N/A
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	7	7	–	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	3	3	–	4
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	17	17	–	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	32	–	(32)	4
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	2	29	27	4
29	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	N/A
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	12	12	–	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	81	80	(1)	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	N/A
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	18	15	(3)	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1,453	1,447	(5)	3
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	–	–	–	N/A
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	222	202	(20)	3
39	HV	Distribution Cable	Distribution UG PILC	km	28	21	(8)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	2	2	–	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	119	149	30	3
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	N/A
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	4,934	4,916	(18)	3
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	N/A
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	189	209	20	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	3,142	3,144	2	3
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	800	850	50	3
48	HV	Distribution Transformer	Voltage regulators	No.	4	4	–	3
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	798	842	44	3
50	LV	LV Line	LV OH Conductor	km	755	735	(19)	3
51	LV	LV Cable	LV UG Cable	km	619	666	47	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	27	47	20	3
53	LV	Connections	OH/UG consumer service connections	No.	41,250	42,078	828	3
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	148	144	(4)	3
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	1	1	–	4
56	All	Capacitor Banks	Capacitors including controls	No	29	29	–	3
57	All	Load Control	Centralised plant	Lot	5	5	–	4
58	All	Load Control	Relays	No	3,568	3,547	(21)	3
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

Company Name **Counties Power Limited**
For Year Ended **31 March 2018**
Network / Sub-network Name

SCHEDULE 9b: ASSET AGE PROFILE

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

sch ref

8 **Disclosure Year (year ended)** 31 March 2018

Number of assets at disclosure year end by installation date

sch ref	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	No. with age unknown	Items at end of year	No. with default dates	Data accuracy (1–4)
9																																		
10	All	Overhead Line	Concrete poles / steel structure	No.	30	23	236	2,242	3,556	6,277	6,643	253	708	377	277	359	350	460	326	418	551	317	333	258	138	244	131	124	1,361	92	13	26,097	–	3
11	All	Overhead Line	Wood poles	No.	–	1	6	62	125	96	499	28	11	11	–	5	6	5	2	5	11	3	5	6	3	7	6	5	931	41	1	1,881	–	3
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	5	–	–	–	–	–	5	–	3
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	–	–	33	31	8	1	–	–	–	–	14	–	–	–	–	–	–	0	–	–	–	–	–	1	–	–	87	–	4
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	3	–	–	–	–	0	21	–	6	–	–	–	–	26	–	–	–	–	–	–	–	10	5	–	–	–	–	72	–	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	–	0	–	–	–	–	–	0	0	–	0	–	–	–	1	–	–	–	–	–	–	–	–	2	–	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	–	–	1	3	1	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7	–	4
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	–	1	–	–	–	–	–	–	1	–	–	0	–	–	–	–	1	–	–	–	–	–	3	–	4
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–	–	–	–	9	6	–	–	–	–	17	–	4
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	13	4	5	3	–	4	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	29	–	4
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	1	–	–	2	–	–	–	–	2	1	–	–	–	–	–	–	–	4	–	–	–	–	2	–	–	12	–	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	9	9	18	12	–	–	–	–	–	–	11	–	–	–	–	–	–	–	21	–	–	–	–	–	80	–	4
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	1	3	2	3	2	–	–	–	–	–	–	2	–	–	–	–	–	–	–	2	–	–	–	–	–	15	–	4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	35	42	77	214	226	316	263	19	20	29	17	9	11	26	13	8	27	18	13	11	8	10	7	8	10	11	–	1,447	–	3
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
38	HV	Distribution Line	SWER conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	–	0	–	–	1	28	7	5	3	4	7	8	16	11	2	9	14	9	9	10	16	17	10	12	2	–	202	–	3
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	5	2	6	7	–	0	–	1	–	–	0	0	–	0	–	–	–	–	0	–	0	–	–	–	21	–	3
41	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	0	–	–	–	–	1	–	–	–	–	–	2	–	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	–	–	–	–	1	13	8	3	2	1	1	–	5	5	5	5	8	9	2	9	11	12	2	6	35	6	–	149	–	3
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	155	66	130	347	476	727	1,365	255	140	94	66	84	144	40	74	122	89	115	94	56	67	58	46	47	48	11	–	4,916	–	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	6	7	10	15	6	2	1	8	2	–	8	8	8	13	11	9	14	7	18	13	14	27	2	–	209	–	3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	22	2	78	84	217	420	723	116	76	119	138	82	38	100	40	73	101	63	192	92	153	115	25	51	23	1	–	3,144	–	3
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	1	1	4	17	21	33	186	41	29	21	42	17	24	42	28	24	31	26	35	25	58	44	26	58	16	–	–	850	–	3
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	1	–	–	1	–	–	–	–	1	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	4	–	3
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	8	3	18	37	62	42	203	51	22	14	15	14	36	13	14	22	17	25	18	20	47	35	29	29	42	6	–	842	–	3
51	LV	LV Line	LV OH Conductor	km	–	–	1	2	3	4	675	7	4	6	3	2	3	2	1	2	4	1	5	2	2	2	1	1	1	–	–	735	–	3
52	LV	LV Cable	LV UG Cable	km	–	–	0	1	8	4	224	23	18	20	17	15	33	42	22	14	7	20	11	21	18	38	28	33	41	9	0	666	–	3
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	–	–	0	0	0	0	2	1	0	1	1	1	0	1	1	1	3	9	6	6	7	6	0	1	0	47	–	3
54	LV	Connections	OH/UG consumer service connections	No.	–	–	–	1	–	11,915	14,429	1,006	535	593	914	947	959	838	857	896	582	584	502	490	682	847	886	1,240	1,235	984	156	42,078	–	3
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	4	16	10	17	2	–	–	–	–	–	–	15	–	–	–	–	4	9	–	17	38	–	12	–	–	144	–	3
56	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	1	–	4
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	23	–	–	–	–	–	–	2	4	–	–	–	–	–	–	–	–	–	–	–	–	29	–	3
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	2	1	–	–	–	–	–	–	1	–	–	–	–	–	–	–	1	–	–	–	–	–	5	–	4
59	All	Load Control	Relays	No	–	–	–	–	–	–	153	382	204	174	133	97	7	8	13	8	6	11	13	3	93	1,159	1,011	67	4	1	–	3,547	–	3
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A

Company Name	**Counties Power Limited**
For Year Ended	**31 March 2018**
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	66	–	66
12	50kV & 66kV	–	–	–
13	33kV	72	2	75
14	SWER (all SWER voltages)	–	–	–
15	22kV (other than SWER)	568	149	717
16	6.6kV to 11kV (inclusive—other than SWER)	900	75	975
17	Low voltage (< 1kV)	735	666	1,402
18	**Total circuit length (for supply)**	2,342	893	3,235
19				
20	Dedicated street lighting circuit length (km)	0	47	47
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	98	4%	
25	Rural	2,159	92%	
26	Remote only	–	–	
27	Rugged only	85	4%	
28	Remote and rugged	–	–	
29	Unallocated overhead lines	–	–	
30	**Total overhead length**	2,342	100%	
31				
32		**Circuit length (km)**	**(% of total circuit length)**	
33	Length of circuit within 10km of coastline or geothermal areas (where known)	1,435	44%	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	2,342	100%	

Company Name	**Counties Power Limited**
For Year Ended	**31 March 2018**

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	Counties Power has no embedded networks		
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	**Counties Power Limited**
For Year Ended	**31 March 2018**
Network / Sub-network Name	

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref

8	**9e(i): Consumer Connections**		
9	*Number of ICPs connected in year by consumer type*		
10	*Consumer types defined by EDB**	**Number of connections (ICPs)**	
11	Urban Residential	367	
12	Urban Commercial	172	
13	Rural Residential	332	
14	Rural Commercial	121	
15			
16	** include additional rows if needed*		
17	**Connections total**	992	
18			
19	**Distributed generation**		
20	Number of connections made in year	102	**connections**
21	Capacity of distributed generation installed in year	0.81	**MVA**
22	**9e(ii): System Demand**		
23			
24			
25	**Maximum coincident system demand**	**Demand at time of maximum coincident demand (MW)**	
26	GXP demand	110	
27	*plus* Distributed generation output at HV and above	7	
28	**Maximum coincident system demand**	116	
29	*less* Net transfers to (from) other EDBs at HV and above		
30	**Demand on system for supply to consumers' connection points**	116	
31	**Electricity volumes carried**	**Energy (GWh)**	
32	Electricity supplied from GXPs	549	
33	*less* Electricity exports to GXPs		
34	*plus* Electricity supplied from distributed generation	42	
35	*less* Net electricity supplied to (from) other EDBs		
36	**Electricity entering system for supply to consumers' connection points**	591	
37	*less* Total energy delivered to ICPs	563	
38	**Electricity losses (loss ratio)**	28	4.7%
39			
40	**Load factor**	0.58	
41	**9e(iii): Transformer Capacity**		
42		**(MVA)**	
43	Distribution transformer capacity (EDB owned)	346	
44	Distribution transformer capacity (Non-EDB owned, estimated)	54	
45	**Total distribution transformer capacity**	400	
46			
47	**Zone substation transformer capacity**	428	

Company Name	**Counties Power Limited**
For Year Ended	**31 March 2018**
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

10(i): Interruptions

sch ref		Number of interruptions	
9	**Interruptions by class**		
10	Class A (planned interruptions by Transpower)	–	
11	Class B (planned interruptions on the network)	403	
12	Class C (unplanned interruptions on the network)	302	
13	Class D (unplanned interruptions by Transpower)	–	
14	Class E (unplanned interruptions of EDB owned generation)	–	
15	Class F (unplanned interruptions of generation owned by others)	–	
16	Class G (unplanned interruptions caused by another disclosing entity)	–	
17	Class H (planned interruptions caused by another disclosing entity)	–	
18	Class I (interruptions caused by parties not included above)	19	
19	**Total**	724	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	177	125
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.67	162.7
27	Class C (unplanned interruptions on the network)	3.37	247.0
28	Class D (unplanned interruptions by Transpower)	–	–
29	Class E (unplanned interruptions of EDB owned generation)	–	–
30	Class F (unplanned interruptions of generation owned by others)	–	–
31	Class G (unplanned interruptions caused by another disclosing entity)	–	–
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	0.01	0.7
34	**Total**	4.05	410.3
35			
36	**Normalised SAIFI and SAIDI**	**Normalised SAIFI**	**Normalised SAIDI**
37	Classes B & C (interruptions on the network)	4.05	371.7
38			
39	**Quality path normalised reliability limit**	**SAIFI reliability limit**	**SAIDI reliability limit**
40	SAIFI and SAIDI limits applicable to disclosure year*	N/A	N/A
41	** not applicable to exempt EDBs*		

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

sch ref		SAIFI	SAIDI
43			
44	**Cause**	**SAIFI**	**SAIDI**
45	Lightning	0.00	0.2
46	Vegetation	0.56	32.9
47	Adverse weather	–	–
48	Adverse environment	–	–
49	Third party interference	0.41	50.9
50	Wildlife	0.17	8.5
51	Human error	–	–
52	Defective equipment	1.42	88.4
53	Cause unknown	0.82	66.1
54			

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

sch ref		SAIFI	SAIDI
56			
57	**Main equipment involved**	**SAIFI**	**SAIDI**
58	Subtransmission lines	–	–
59	Subtransmission cables	–	–
60	Subtransmission other	–	–
61	Distribution lines (excluding LV)	0.58	146.6
62	Distribution cables (excluding LV)	0.08	16.0
63	Distribution other (excluding LV)	0.00	0.1

Company Name	Counties Power Limited
For Year Ended	31 March 2018
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.

64 **10(iv): Class C Interruptions and Duration by Main Equipment Involved**

65

		SAIFI	SAIDI
66	**Main equipment involved**		
67	Subtransmission lines	0.01	0.6
68	Subtransmission cables	–	–
69	Subtransmission other	0.05	1.5
70	Distribution lines (excluding LV)	2.81	223.6
71	Distribution cables (excluding LV)	0.02	0.6
72	Distribution other (excluding LV)	0.49	20.8

73 **10(v): Fault Rate**

		Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
74	**Main equipment involved**			
75	Subtransmission lines	2	159	1.26
76	Subtransmission cables	–	2	–
77	Subtransmission other	1		
78	Distribution lines (excluding LV)	287	1,447	19.83
79	Distribution cables (excluding LV)	5	224	2.23
80	Distribution other (excluding LV)	8		
81	**Total**	303		

Company Name	Counties Power Limited
For Year Ended	31 March 2018

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

Classification is consistent with previous treatment.

CPI of 1.1% (FY17 – 2.2%) was the primary reason for the ROI decrease this year. Removing the impact of CPI, ROI would have seen an increase of 0.6% from FY17.

Operational costs decreased as a % of Line charge revenue from 26.2% in FY17 to 24.7% in FY18. In the prior year, routine corrective maintenance included $500k for an audit across the network to ensure all poles were identified and safety checked.

Recoverable costs increased by $400k in FY18 which was due mainly to higher distributed generation allowances of $342k.

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
Line charge revenue and operational expenditure excludes non-regulated Smart Meters. Other regulated income includes only standard recoveries relating to the regulated business (eg electricity reserve market and customer recoveries related to the Regulatory business that are not capital receipts). There were no changes in classification within regulatory profit this disclosure year.

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
No mergers or acquisitions for the regulated business occurred during the disclosure year.

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 no changes to classifications or the method of allocating RAB into the asset categories from FY17. Assets being disposed of comprise non-system minor plant and equipment ($2k) and transformers sold as scrap ($107k).

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

Items included in permanent differences are the difference between gain/loss on sale of regulatory assets used for the regulatory P&L and the equivalent calculation for tax purposes and permanent differences (eg non-deductible entertainment).

8.1 Income not included in regulatory profit before tax but taxable (Nil).

8.2 Expenditure or loss in regulatory profit before tax but not deductible (accounting vs tax loss on disposal - $18k and entertainment expense - $21k).

8.3 Income included in regulatory profit before tax but not taxable (regulatory asset revaluation - $2,654k).

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)

Temporary differences relate to holiday pay provisions, gratuity and sick leave provisions and doubtful debt provisions as they related to the regulated business. The movement in these provisions has been multiplied by the tax rate to calculate the deferred tax figure ($62k @28% = $17k).

Holiday Pay - $263k (FY17 - $280k)

Gratuity & Sick leave Provision - $152k (FY17 - $106k)

Doubtful Debts - $309k (FY17 - $276k)

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

Counties Power Limited's related party is Field Operations which is a division of the Company. The related party completes work for the Asset Management division and also performs fault and emergency services as required. Charges are made to the Asset Management division for this work with documentation provided to the Finance department.

Analysis has been carried out for the 2012 to 2018 financial years to determine a revenue and expense split within the Field Operations department to confirm that the mark-up percentage for electrical contracting services does not exceed the 17.2% referenced in clause 2.3.6 (1) (b).

Charges from the related party have been transferred to Asset Management at cost during FY18 which is consistent with FY17 treatment.

The related party component of major projects is primarily normal labour, vehicle and plant costs. Materials on the major projects programs have been sourced by the Field Operations division.

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

Cost allocations were historically calculated using ACAM methodology per the IM Determination for business support.

In the current financial year, only costs directly attributable to the electricity distribution services were included. These costs were found to be consistent with the amounts calculated using ACAM methodology.

There have been no other changes in classification in FY18.

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

There is only very limited shared usage of assets in the non-network assets category.

In prior years, Business support, corporate overheads and customer care assets were allocated to regulated and unregulated services using proxy cost allocators.

Following a review, it was determined that asset allocations historically treated as not directly attributable are of such a low magnitude they are not considered avoidable. A difference of $593k has been calculated in schedule 5e (0.2% adjustment to the closing RAB).

No other items have been reclassified during the disclosure year.

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

13.1: Consumer types are based on historical AMP descriptions. There were $50k of relocations this year. Treatment for all other categories was to sum the many small projects (under $100k) by significant core drivers.

13.2: Classification is consistent with previous treatment.

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
14.1: Operational expenditure includes items such as cable and conductor repairs, insulator replacements, transformer and switch repairs, and other work of a non-capital nature. 14.2: Classification is consistent with previous treatment.

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

(i): The variance between actual and forecast line charge revenue is minimal.

(ii): Variances above 10% listed by category:

- Consumer connection expenditure was 58% above forecast. The unfavourable variance was due to a higher than expected volume of new subdivisions. The forecast was based on the previous year's average and adjusted for known projects;
- System growth expenditure was 38% below forecast due to a deferral of the Great South Road Feeder Upgrade, Installation of the RMU on Railway Feeder, and Port Waikato feeder capacity upgrade projects;
- Asset relocations expenditure was 83% below forecast due to a lower than expected volume of asset relocation requests and deferral of 110kV line relocation for Drury South business park development;
- Other reliability, safety and environment was 53% below forecast due to a lower than expected volume of quality of supply improvement requests, and deferral of projects to improve reliability of Whangarata and Hitchen Road Feeders and Pukekohe-Tuakau 110kV line corridor visual mitigation measures;
- Expenditure on non-network assets was 52% below forecast due to a deferral of new IT systems to FY18.

(iii): Variances above 10% listed by category:

- Service interruptions and emergencies was 15% above target due to a higher number of storm events in FY18;
- Routine and corrective maintenance and inspection was 24% higher than budget to address specific asset performance issues;
- Asset replacement and renewal was 17% below budget with resource reallocated to address the specific asset performance issues noted above.

(iv): Energy efficiency and R&D are not yet measured.

(v): Insurance and R&D expenditure are the only subcomponents of operational expenditure identified and measured. The insurance variance reflects higher premium rates and the growth in the network.

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
16.1: Target revenue disclosed according to clauses 2.4.1 and 2.4.3(3) $51.7m. Total billed line charge revenue for the disclosure year, as disclosed in Schedule 8 $52.3m. 16.2: The difference between target and total billed line charge revenue is not material.

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.

Box 14: Commentary on network reliability for the disclosure year

Unplanned outages, as measured by SAIDI, exceeded the target by 98.6 minutes (89% unfavourable). Contributing factors to the unfavourable result included four major event days and an increase in severe weather events predominantly affecting the overhead network (overhead equipment and vegetation. The main fault causes were overhead equipment failure, car v pole events, out of zone trees and an increase in 'no fault found' events. A continued focus on identifying and implementing prudent investment and operational strategies to improve network performance is underway.

Planned SAIDI exceeded the target by 103.1 minutes (21.58 minutes under DPP normalisation). The main contributors to the unfavourable result were a reduction in live work and a large works programme of maintenance and asset replacement and customer initiated work.

SAIFI performance was unfavourable to target due to the nature of unplanned outages, whereby large groups of ICPs were impacted in single events, as well as repeat outages on some highly populated feeders.

The SAIDI and SAIFI results are calculated using information from non-financial systems which includes the manual recording of some outage types. Consequently, there is an inherent limitation in the company's ability to maintain unplanned outage records sufficient to ensure complete and accurate disclosure of class C network reliability statistics.

The normalisation methodology used in previous years did not align with the information disclosure requirements. Prior year figures were normalised using the 2015 Default Price-Quality Path Determination, resulting in an understatement of the underlying performance. The impact has been retrospectively assessed and is considered to be immaterial to the ID schedules as a whole. The updated information as set out below should, however, be used when assessing historic trends for comparability.

The following table outlines our original calculations and the recalculations using the information disclosure methodology:

Item	2015/16		2016/17	
	Original	Recalculation	Original	Recalculation
SAIDI	118.30	141.66	236.6	329.86
SAIFI	2.70	3.49	3.28	3.72

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
Essential equipment is insured under a materials damage policy and this cover is reviewed annually. The material damage cover is for physical loss or damage including earthquake natural disaster cover. Other than key substations and essential equipment, the bulk of the Network system is not covered by insurance due to the inability to get sufficient cover from the insurance industry for such assets, at an acceptable cost.

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 have been no material amendments to previously disclosed information pursuant to clause 2.12.1 disclosed in the last 8 years.

Company Name	Counties Power Limited
For Year Ended	31 March 2018

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
The difference between nominal and constant prices reflects inflation of 1.1% per annum.

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
The difference between nominal and constant prices reflects inflation of 1.1% per annum.

Company Name	Counties Power Limited
For Year Ended	31 March 2018

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
There are no voluntary disclosures this year.

Schedule 18 Certification for Year-end Disclosures

Clause 2.9.2

We, Douglas John Troon and Hamish William Stevens, being directors of Counties Power Limited certify that subject to the limitation expressed below, 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 Counties Power Limited's accounting and other records sourced from its financial and nonfinancial systems, and that sufficient appropriate records have been retained.

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 arms-length.

As described in box 14 of schedule 14, the SAIDI and SAIFI results are calculated using information from non-financial systems which includes the manual recording of some outage types. Consequently, there is an inherent limitation on the company's ability to maintain unplanned outage records sufficient to ensure complete and accurate disclosure of class C network reliability statistics.

DJ Troon
22 August 2018

HW Stevens
22 August 2018

INDEPENDENT ASSURANCE REPORT
TO THE DIRECTORS OF COUNTIES POWER LIMITED AND THE COMMERCE COMMISSION

The Auditor-General is the auditor of Counties Power Limited (the company). The Auditor-General has appointed me, Mark Bramley, using the staff and resources of PricewaterhouseCoopers, to provide an opinion, on his 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 2018, 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* and the Standard on Assurance Engagements 3100 (Revised): *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.

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 his employees, and PricewaterhouseCoopers and its partners and 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, the annual audit of the company's financial statements, regulatory compliance and other advisory services that are compatible with the Auditor-General's independence requirements, we have no relationship with or interests in the company and its subsidiaries.

Qualified Opinion on schedules 10(i), (ii) and (iv)

As described in Box 14 of Schedule 14, there are inherent limitations in the ability of the company to collect and record the Class C network reliability information required to be disclosed in Schedules 10(i), (ii) and (iv). Consequently, there is no independent evidence available to support the completeness and accuracy of recorded Class C faults.

There are no practical audit procedures that we could adopt to confirm independently that all the Class C data was properly recorded for the purposes of inclusion in the amounts relating to quality measures set out in Schedules 10(i), (ii) and (iv). Because of the potential effect of these limitations, we are unable to form an opinion as the completeness and accuracy of the Class C data that forms the basis of the compilation of Schedules 10(i), (ii) and (iv).

In these respects alone we have not obtained all the recorded evidence and explanations that we have required.

In our opinion, except for the matters described above:

- 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.

Mark Bramley

Mark Bramley
PricewaterhouseCoopers
On behalf of the Auditor-General
Auckland, New Zealand
23 August 2018