COUNTIES POWER

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

For the Year Ended 31 March 2019

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Company Name	**Counties Power Limited**
For Year Ended	**31 March 2019**

SCHEDULE 1: ANALYTICAL RATIOS

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

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

sch ref

7 **1(i): Expenditure metrics**

sch ref		Expenditure per GWh energy delivered to ICPs ($/GWh)	Expenditure per average no. of ICPs ($/ICP)	Expenditure per MW maximum coincident system demand ($/MW)	Expenditure per km circuit length ($/km)	Expenditure per MVA of capacity from EDB-owned distribution transformers ($/MVA)
8						
9	**Operational expenditure**	25,051	344	113,897	4,498	41,109
10	Network	8,078	111	36,730	1,451	13,257
11	Non-network	16,972	233	77,167	3,047	27,852
12						
13	**Expenditure on assets**	60,722	835	276,082	10,903	99,647
14	Network	51,253	705	233,028	9,203	84,107
15	Non-network	9,469	130	43,054	1,700	15,540
16						

17 **1(ii): Revenue metrics**

sch ref		Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
18			
19	**Total consumer line charge revenue**	89,274	1,227
20	Standard consumer line charge revenue	96,187	1,165
21	Non-standard consumer line charge revenue	38,110	378,286
22			

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

sch ref			
24			
25	Demand density	39	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
26	Volume density	180	*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	13,749	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*
29			

30 **1(iv): Composition of regulatory income**

sch ref		($000)	% of revenue
31			
32	Operational expenditure	14,624	27.90%
33	Pass-through and recoverable costs excluding financial incentives and wash-ups	13,523	25.80%
34	Total depreciation	8,228	15.70%
35	Total revaluations	3,754	7.16%
36	Regulatory tax allowance	3,054	5.83%
37	Regulatory profit/(loss) including financial incentives and wash-ups	16,738	31.93%
38	**Total regulatory income**	52,413	
39			

40 **1(v): Reliability**

sch ref			
41			
42	Interruption rate	21.87	*Interruptions per 100 circuit km*

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SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

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

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

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

sch ref		CY-2	CY-1	Current Year CY
7	**2(i): Return on Investment**			
8		**31 Mar 17**	**31 Mar 18**	**31 Mar 19**
9	**ROI – comparable to a post tax WACC**	**%**	**%**	**%**
10	Reflecting all revenue earned	7.73%	7.04%	6.35%
11	Excluding revenue earned from financial incentives	7.73%	7.04%	6.35%
12	Excluding revenue earned from financial incentives and wash-ups	7.73%	7.04%	6.35%
13				
14	**Mid-point estimate of post tax WACC**	4.77%	5.04%	4.75%
15	25th percentile estimate	4.05%	4.36%	4.07%
16	75th percentile estimate	5.48%	5.72%	5.43%
17				
18				
19	**ROI – comparable to a vanilla WACC**			
20	Reflecting all revenue earned	8.27%	7.63%	6.86%
21	Excluding revenue earned from financial incentives	8.27%	7.63%	6.86%
22	Excluding revenue earned from financial incentives and wash-ups	8.27%	7.63%	6.86%
23				
24	**WACC rate used to set regulatory price path**			
25				
26	**Mid-point estimate of vanilla WACC**	5.31%	5.60%	5.26%
27	25th percentile estimate	4.59%	4.92%	4.58%
28	75th percentile estimate	6.03%	6.29%	5.94%
29				

sch ref	**2(ii): Information Supporting the ROI**		**($000)**	
30				
31				
32	Total opening RAB value	253,205		
33	*plus* Opening deferred tax	(13,868)		
34	**Opening RIV**		239,338	
35				
36	**Line charge revenue**		52,116	
37				
38	Expenses cash outflow	28,147		
39	*add* Assets commissioned	22,431		
40	*less* Asset disposals	92		
41	*add* Tax payments	1,263		
42	*less* Other regulated income	297		
43	**Mid-year net cash outflows**		51,451	
44				
45	**Term credit spread differential allowance**		–	
46				
47	Total closing RAB value	270,478		
48	*less* Adjustment resulting from asset allocation	(592)		
49	*less* Lost and found assets adjustment	–		
50	*plus* Closing deferred tax	(15,659)		
51	**Closing RIV**		255,411	
52				
53	**ROI – comparable to a vanilla WACC**			6.86%
54				
55	Leverage (%)			42%
56	Cost of debt assumption (%)			4.33%
57	Corporate tax rate (%)			28%
58				
59	**ROI – comparable to a post tax WACC**			6.35%
60				

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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

61 2(iii): Information Supporting the Monthly ROI

sch ref		Line charge revenue	Expenses cash outflow	Assets commissioned	Asset disposals	Other regulated income	Monthly net cash outflows
63	**Opening RIV**						N/A
67	April						–
68	May						–
69	June						–
70	July						–
71	August						–
72	September						–
73	October						–
74	November						–
75	December						–
76	January						–
77	February						–
78	March						–
79	**Total**	–	–	–	–	–	–
81	**Tax payments**						N/A
83	**Term credit spread differential allowance**						N/A
85	**Closing RIV**						N/A
88	**Monthly ROI – comparable to a vanilla WACC**						N/A
90	**Monthly ROI – comparable to a post tax WACC**						N/A

92 2(iv): Year-End ROI Rates for Comparison Purposes

sch ref		
94	**Year-end ROI – comparable to a vanilla WACC**	6.68%
96	**Year-end ROI – comparable to a post tax WACC**	6.17%

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.*

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

sch ref			
102	Net recoverable costs allowed under incremental rolling incentive scheme	–	
103	Purchased assets – avoided transmission charge		
104	Energy efficiency and demand incentive allowance		
105	Quality incentive adjustment		
106	Other financial incentives		
107	**Financial incentives**		–
109	**Impact of financial incentives on ROI**		–
111	Input methodology claw-back		
112	CPP application recoverable costs		
113	Catastrophic event allowance		
114	Capex wash-up adjustment		
115	Transmission asset wash-up adjustment		
116	2013–15 NPV wash-up allowance		
117	Reconsideration event allowance		
118	Other wash-ups		
119	**Wash-up costs**		–
121	**Impact of wash-up costs on ROI**		–

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SCHEDULE 3: REPORT ON REGULATORY PROFIT

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

sch ref			
7		**3(i): Regulatory Profit**	**($000)**
8		**Income**	
9		Line charge revenue	52,116
10	*plus*	Gains / (losses) on asset disposals	(43)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)	340
12			
13		**Total regulatory income**	52,413
14		**Expenses**	
15	*less*	Operational expenditure	14,624
16			
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups	13,523
18			
19		**Operating surplus / (deficit)**	24,266
20			
21	*less*	Total depreciation	8,228
22			
23	*plus*	Total revaluations	3,754
24			
25		**Regulatory profit / (loss) before tax**	19,792
26			
27	*less*	Term credit spread differential allowance	–
28			
29	*less*	Regulatory tax allowance	3,054
30			
31		**Regulatory profit/(loss) including financial incentives and wash-ups**	16,738
32			

33	**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	**($000)**	
34	**Pass through costs**		
35	Rates	692	
36	Commerce Act levies	99	
37	Industry levies	112	
38	CPP specified pass through costs		
39	**Recoverable costs excluding financial incentives and wash-ups**		
40	Electricity lines service charge payable to Transpower	11,608	
41	Transpower new investment contract charges	230	
42	System operator services		
43	Distributed generation allowance	782	
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**		13,523
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 18**	**31 Mar 19**
51	Allowed controllable opex			
52	Actual controllable opex			
53				
54	Incremental change in year			
55				
56			**Previous years' incremental change**	**Previous years' incremental change adjusted for inflation**
57	CY-5	31 Mar 14		
58	CY-4	31 Mar 15		
59	CY-3	31 Mar 16		
60	CY-2	31 Mar 17		
61	CY-1	31 Mar 18		
62	**Net incremental rolling incentive scheme**			–
63				
64	**Net recoverable costs allowed under incremental rolling incentive scheme**			–
65	**3(iv): Merger and Acquisition Expenditure**			
70				**($000)**
66	Merger and acquisition expenditure			
67				
68	*Provide commentary on the benefits of merger and acquisition expenditure to the electricity distribution business, including required disclosures in accordance with section 2.7, in Schedule 14 (Mandatory Explanatory Notes)*			
69	**3(v): Other Disclosures**			
70				**($000)**
71	Self-insurance allowance			

Company Name	**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 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**
		($000)	**($000)**	**($000)**	**($000)**	**($000)**
	Total opening RAB value	210,305	228,249	231,077	241,528	253,205
less	**Total depreciation**	7,132	7,623	7,690	7,899	8,228
plus	**Total revaluations**	176	1,337	4,997	2,661	3,754
plus	**Assets commissioned**	25,260	9,361	13,336	16,432	22,431
less	**Asset disposals**	360	247	193	108	92
plus	**Lost and found assets adjustment**					–
plus	**Adjustment resulting from asset allocation**				593	(592)
	Total closing RAB value	228,249	231,077	241,528	253,205	270,478

4(ii): Unallocated Regulatory Asset Base

		Unallocated RAB *		RAB	
		($000)	**($000)**	**($000)**	**($000)**
	Total opening RAB value		253,205		253,205
less					
	Total depreciation		8,268		8,228
plus					
	Total revaluations		3,754		3,754
plus					
	Assets commissioned (other than below)	22,757		22,431	
	Assets acquired from a regulated supplier	–		–	
	Assets acquired from a related party	–		–	
	Assets commissioned		22,757		22,431
less					
	Asset disposals (other than below)	92		92	
	Asset disposals to a regulated supplier	–		–	
	Asset disposals to a related party	–		–	
	Asset disposals		92		92
plus	**Lost and found assets adjustment**				
plus	**Adjustment resulting from asset allocation**				(592)
	Total closing RAB value		271,355		270,478

** 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	1,026
CPI_4^{-4}	1,011
Revaluation rate (%)	1.48%

		Unallocated RAB *		RAB	
		($000)	**($000)**	**($000)**	**($000)**
	Total opening RAB value	253,205		253,205	
less	Opening value of fully depreciated, disposed and lost assets	217		217	
	Total opening RAB value subject to revaluation	252,988		252,988	
	Total revaluations		3,754		3,754

4(iv): Roll Forward of Works Under Construction

		Unallocated works under construction		Allocated works under construction	
	Works under construction—preceding disclosure year		1,271		1,271
plus	Capital expenditure	26,657		26,331	
less	Assets commissioned	22,757		22,431	
plus	Adjustment resulting from asset allocation				
	Works under construction - current disclosure year		5,171		5,171
	Highest rate of capitalised finance applied				–

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

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

sch ref

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

sch ref		Unallocated RAB *		RAB	
78		($000)	($000)	($000)	($000)
79	Depreciation - standard	7,652		7,652	
80	Depreciation - no standard life assets	616		576	
81	Depreciation - modified life assets				
82	Depreciation - alternative depreciation in accordance with CPP				
83	**Total depreciation**		8,268		8,228
84					

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

($000 unless otherwise specified)

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

95 ** include additional rows if needed*

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

97 ($000 unless otherwise specified)

sch ref			Subtransmission lines	Subtransmission cables	Zone substations	Distribution and LV lines	Distribution and LV cables	Distribution substations and transformers	Distribution switchgear	Other network assets	Non-network assets	Total
99		**Total opening RAB value**	17,213	225	21,694	94,773	39,494	40,755	10,919	6,092	22,040	253,205
100	*less*	Total depreciation	438	8	650	2,455	1,343	1,472	718	471	673	8,228
101	*plus*	Total revaluations	256	3	322	1,406	586	603	162	91	325	3,754
102	*plus*	Assets commissioned	75	–	935	5,335	6,169	942	3,300	147	5,528	22,431
103	*less*	Asset disposals	–	–	–	–	–	70	–	–	22	92
104	*plus*	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
105	*plus*	Adjustment resulting from asset allocation	–	–	–	–	–	–	–	–	(592)	(592)
106	*plus*	Asset category transfers	–	–	–	–	–	–	–	–	–	–
107		**Total closing RAB value**	17,106	220	22,301	99,059	44,906	40,758	13,663	5,859	26,606	270,478
108												
109		**Asset Life**										
110		Weighted average remaining asset life	45.6	27.3	34.3	44.7	37.1	32.7	28.1	9.8	14.4	(years)
111		Weighted average expected total asset life	59.1	45.0	45.1	59.3	50.4	45.0	36.4	13.9	21.2	(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					
7	**5a(i): Regulatory Tax Allowance**			**($000)**	
8		**Regulatory profit / (loss) before tax**		19,792	
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	32		*
12		Amortisation of initial differences in asset values	2,680		
13		Amortisation of revaluations	770		
14				3,482	
15					
16	*less*	Total revaluations	3,754		
17		Income included in regulatory profit / (loss) before tax but not taxable			*
18		Discretionary discounts and customer rebates	4,353		
19		Expenditure or loss deductible but not in regulatory profit / (loss) before tax			*
20		Notional deductible interest	4,261		
21				12,368	
22					
23		**Regulatory taxable income**		10,906	
24					
25	*less*	Utilised tax losses			
26		Regulatory net taxable income		10,906	
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**		3,054	
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	74,608		
37	*less*	Amortisation of initial differences in asset values	2,680		
38	*plus*	Adjustment for unamortised initial differences in assets acquired			
39	*less*	Adjustment for unamortised initial differences in assets disposed	16		
40		Closing unamortised initial differences in asset values		71,911	
41					
42		Opening weighted average remaining useful life of relevant assets (years)		28	
43					

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SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

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

sch ref				
44		**5a(iv): Amortisation of Revaluations**		**($000)**
45				
46		Opening sum of RAB values without revaluations	231,447	
47				
48		Adjusted depreciation	7,458	
49		Total depreciation	8,228	
50		Amortisation of revaluations		770
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**	(13,868)	
61				
62	*plus*	Tax effect of adjusted depreciation	2,088	
63				
64	*less*	Tax effect of tax depreciation	3,123	
65				
66	*plus*	Tax effect of other temporary differences*	8	
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	(10)	
75				
76		**Closing deferred tax**		(15,659)
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**	109,563	
84	*less*	Tax depreciation	11,152	
85	*plus*	Regulatory tax asset value of assets commissioned	22,431	
86	*less*	Regulatory tax asset value of asset disposals	65	
87	*plus*	Lost and found assets adjustment		
88	*plus*	Adjustment resulting from asset allocation	(628)	
89	*plus*	Other adjustments to the RAB tax value		
90		**Closing sum of regulatory tax asset values**		120,149

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SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

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

sch ref		($000)	($000)
7	**5b(i): Summary—Related Party Transactions**		
8	**Total regulatory income**		
9			
10	**Market value of asset disposals**		
11			
12	Service interruptions and emergencies	–	
13	Vegetation management	–	
14	Routine and corrective maintenance and inspection	–	
15	Asset replacement and renewal (opex)	–	
16	**Network opex**		–
17	Business support	–	
18	System operations and network support	–	
19	**Operational expenditure**		–
20	Consumer connection	–	
21	System growth	–	
22	Asset replacement and renewal (capex)	–	
23	Asset relocations	–	
24	Quality of supply	–	
25	Legislative and regulatory	–	
26	Other reliability, safety and environment	–	
27	**Expenditure on non-network assets**		–
28	**Expenditure on assets**		–
29	Cost of financing		
30	Value of capital contributions		
31	Value of vested assets		
32	**Capital Expenditure**		–
33	**Total expenditure**		–
34			
35	**Other related party transactions**		

36 5b(iii): Total Opex and Capex Related Party Transactions

sch ref	Name of related party	Nature of opex or capex service provided	Total value of transactions ($000)
37			
38		[Select one]	
39		[Select one]	
40		[Select one]	
41		[Select one]	
42		[Select one]	
43		[Select one]	
44		[Select one]	
45		[Select one]	
46		[Select one]	
47		[Select one]	
48		[Select one]	
49		[Select one]	
50		[Select one]	
51		[Select one]	
52		[Select one]	
53	**Total value of related party transactions**		–
54	** include additional rows if needed*		
55			

Company Name	**Counties Power Limited**
For Year Ended	**31 March 2019**

SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

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

sch ref

7
8 **5c(i): Qualifying Debt (may be Commission only)**
9

sch ref	Issuing party	Issue date	Pricing date	Original tenor (in years)	Coupon rate (%)	Book value at issue date (NZD)	Book value at date of financial statements (NZD)	Term Credit Spread Difference	Debt issue cost readjustment
11	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	42%	
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 2019**

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref

5d(i): Operating Cost Allocations

	Arm's length deduction	Value allocated ($000s) Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
Service interruptions and emergencies					
Directly attributable		2,025			
Not directly attributable				–	
Total attributable to regulated service		2,025			
Vegetation management					
Directly attributable		1,006			
Not directly attributable				–	
Total attributable to regulated service		1,006			
Routine and corrective maintenance and inspection					
Directly attributable		1,030			
Not directly attributable				–	
Total attributable to regulated service		1,030			
Asset replacement and renewal					
Directly attributable		655			
Not directly attributable				–	
Total attributable to regulated service		655			
System operations and network support					
Directly attributable		3,547			
Not directly attributable				–	
Total attributable to regulated service		3,547			
Business support					
Directly attributable		339			
Not directly attributable		6,022	854	6,876	
Total attributable to regulated service		6,361			
Operating costs directly attributable		8,602			
Operating costs not directly attributable	–	6,022	854	6,876	–
Operational expenditure		14,624			

5d(ii): Other Cost Allocations

Pass through and recoverable costs	($000)
Pass through costs	
Directly attributable	855
Not directly attributable	48
Total attributable to regulated service	903
Recoverable costs	
Directly attributable	12,620
Not directly attributable	
Total attributable to regulated service	12,620

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

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

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

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

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

Company Name	**Counties Power Limited**
For Year Ended	**31 March 2019**

SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

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

sch ref

5e(i): Regulated Service Asset Values

	Value allocated ($000s) Electricity distribution services
Subtransmission lines	
Directly attributable	17,106
Not directly attributable	
Total attributable to regulated service	17,106
Subtransmission cables	
Directly attributable	220
Not directly attributable	
Total attributable to regulated service	220
Zone substations	
Directly attributable	22,301
Not directly attributable	
Total attributable to regulated service	22,301
Distribution and LV lines	
Directly attributable	99,059
Not directly attributable	
Total attributable to regulated service	99,059
Distribution and LV cables	
Directly attributable	44,906
Not directly attributable	
Total attributable to regulated service	44,906
Distribution substations and transformers	
Directly attributable	40,758
Not directly attributable	
Total attributable to regulated service	40,758
Distribution switchgear	
Directly attributable	13,663
Not directly attributable	
Total attributable to regulated service	13,663
Other network assets	
Directly attributable	5,859
Not directly attributable	
Total attributable to regulated service	5,859
Non-network assets	
Directly attributable	24,475
Not directly attributable	2,131
Total attributable to regulated service	26,606
Regulated service asset value directly attributable	268,347
Regulated service asset value not directly attributable	2,131
Total closing RAB value	270,478

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

			($000) CY-1	($000) Current Year (CY)
Change in asset value allocation 1				
Asset category	Non-network assets	Original allocation	22,040	27,198
Original allocator or line items	Directly Atttributable	New allocation	21,448	26,606
New allocator or line items	ABAA	Difference	592	592

Rationale for change: A review of non-network assets was undertaken to allocate underlying assets using ABAA methodology. For property assets not directly allocated, space usage was used as the proxy allocator. For Finance, IT and Corporate costs, resource was used as the proxy allocator.

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

Rationale for change

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

Rationale for change

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

Company Name	**Counties Power Limited**
For Year Ended	**31 March 2019**

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

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

sch ref				
7		**6a(i): Expenditure on Assets**	**($000)**	**($000)**
8		Consumer connection		10,722
9		System growth		8,525
10		Asset replacement and renewal		9,372
11		Asset relocations		144
12		Reliability, safety and environment:		
13		Quality of supply	841	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	316	
16		**Total reliability, safety and environment**		1,157
17		**Expenditure on network assets**		29,920
18		Expenditure on non-network assets		5,528
19				
20		**Expenditure on assets**		35,448
21	*plus*	Cost of financing		
22	*less*	Value of capital contributions		9,117
23	*plus*	Value of vested assets		
24				
25		**Capital expenditure**		26,331
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		3,049
29		Research and development		
30		**6a(iii): Consumer Connection**		
31		*Consumer types defined by EDB**	**($000)**	**($000)**
32		Urban residential	3,460	
33		Urban commercial	379	
34		Rural residential	6,018	
35		Rural commercial	865	
36				
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		10,722
39				
40	*less*	Capital contributions funding consumer connection expenditure	9,117	
41		**Consumer connection less capital contributions**		1,605
42		**6a(iv): System Growth and Asset Replacement and Renewal**		**Asset Replacement and**
43			**System Growth**	**Renewal**
44			**($000)**	**($000)**
45		Subtransmission	78	11
46		Zone substations	3,838	203
47		Distribution and LV lines	2,253	3,768
48		Distribution and LV cables	1,883	2,239
49		Distribution substations and transformers	318	675
50		Distribution switchgear	155	2,369
51		Other network assets	–	107
52		**System growth and asset replacement and renewal expenditure**	8,525	9,372
53	*less*	Capital contributions funding system growth and asset replacement and renewal		
54		**System growth and asset replacement and renewal less capital contributions**	8,525	9,372
55				
56		**6a(v): Asset Relocations**		
57		*Project or programme**	**($000)**	**($000)**
58		Kahawai Point	54	
59		Glasgow Road Pukekohe Transformer	40	
60		Drury South Ararimu Road	50	
61				
62				
63		** include additional rows if needed*		
64		All other projects or programmes - asset relocations	–	
65		**Asset relocations expenditure**		144
66	*less*	Capital contributions funding asset relocations		
67		**Asset relocations less capital contributions**		144
68				

Company Name	**Counties Power Limited**
For Year Ended	**31 March 2019**

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

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

sch ref				
69		**6a(vi): Quality of Supply**		
70		*Project or programme**	**($000)**	**($000)**
71		Tuakau power quality	511	
72		Dent Place, Papakura rehabilitation	76	
73		Voltage improvements (multiple locations)	153	
74		Other quality improvement projects	101	
75				
76		** include additional rows if needed*		
77		All other projects programmes - quality of supply	–	
78		**Quality of supply expenditure**		841
79	*less*	Capital contributions funding quality of supply	–	
80		**Quality of supply less capital contributions**		841
81		**6a(vii): Legislative and Regulatory**		
82		*Project or programme**	**($000)**	**($000)**
83		Nil		
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		Outage impact mitigation Pukekohe feeders	99	
96		Whangarata and Hitchen Road feeders	166	
97		Other projects	51	
98				
99				
100		** include additional rows if needed*		
101		All other projects or programmes - other reliability, safety and environment		
102		**Other reliability, safety and environment expenditure**		316
103	*less*	Capital contributions funding other reliability, safety and environment		
104		**Other reliability, safety and environment less capital contributions**		316
105				
106		**6a(ix): Non-Network Assets**		
107		**Routine expenditure**		
108		*Project or programme**	**($000)**	**($000)**
109		Building upgrades	2,188	
110		IT software	1,895	
111		Land - substation	750	
112		Other equipment	695	
113			–	
114		** include additional rows if needed*		
115		All other projects or programmes - routine expenditure		
116		**Routine expenditure**		5,528
117		**Atypical expenditure**		
118		*Project or programme**	**($000)**	**($000)**
119				
120				
121				
122				
123				
124		** include additional rows if needed*		
125		All other projects or programmes - atypical expenditure		
126		**Atypical expenditure**		–
127				
128		**Expenditure on non-network assets**		5,528

Company Name	**Counties Power Limited**
For Year Ended	**31 March 2019**

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

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

sch ref			
7	**6b(i): Operational Expenditure**	**($000)**	**($000)**
8	Service interruptions and emergencies	2,025	
9	Vegetation management	1,006	
10	Routine and corrective maintenance and inspection	1,030	
11	Asset replacement and renewal	655	
12	**Network opex**		4,716
13	System operations and network support	3,547	
14	Business support	6,361	
15	**Non-network opex**		9,908
16			
17	**Operational expenditure**		14,624
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		339
23	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**Counties Power Limited**
For Year Ended	**31 March 2019**

SCHEDULE 7: COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE

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

sch ref				
7	**7(i): Revenue**	**Target ($000) [1]**	**Actual ($000)**	**% variance**
8	Line charge revenue	51,340	52,116	2%
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	10,000	10,722	7%
11	System growth	6,990	8,525	22%
12	Asset replacement and renewal	11,295	9,372	(17%)
13	Asset relocations	3,225	144	(96%)
14	Reliability, safety and environment:			
15	Quality of supply	1,350	841	(38%)
16	Legislative and regulatory		–	–
17	Other reliability, safety and environment	295	316	7%
18	**Total reliability, safety and environment**	1,645	1,157	(30%)
19	**Expenditure on network assets**	33,155	29,920	(10%)
20	Expenditure on non-network assets	2,450	5,528	126%
21	Expenditure on assets	35,605	35,448	(0%)
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	1,900	2,025	7%
24	Vegetation management	1,100	1,006	(9%)
25	Routine and corrective maintenance and inspection	1,350	1,030	(24%)
26	Asset replacement and renewal	800	655	(18%)
27	**Network opex**	5,150	4,716	(8%)
28	System operations and network support	3,717	3,547	(5%)
29	Business support	5,582	6,361	14%
30	**Non-network opex**	9,299	9,908	7%
31	**Operational expenditure**	14,449	14,624	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	–	3,049	–
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	272	339	25%
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 2019
ork / 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	7,130	105,955
3 Rate	Commercial	Standard	119	8,956
Standard Domestic	Residential	Standard	20,038	193,208
Low User Domestic	Residential	Standard	14,342	80,560
Prepaid Domestic	Residential	Standard	636	3,332
Time Of Use	Commercial	Standard	167	120,424
Streetlights	Commercial	Standard	19	1,855
Major Customer A	Commercial	Non-standard	4	39,762
Major Customer B	Commercial	Non-standard	1	15,478
Major Customer C	Commercial	Non-standard	2	14,243
Add extra rows for additional consumer groups or price category codes as necessary				
		Standard consumer totals	42,451	514,290
		Non-standard consumer totals	7	69,483
		Total for all consumers	42,458	583,773

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	-	-	-	97,011	296	7,187	-	789	433	-	–
3 Rate	-	-	-	90	-	195	-	2,176	3,962	-	-
Standard Domestic	-	-	-	145,548	-	47,657	-	-	-	-	3
Low User Domestic	-	-	-	57,677	-	22,882	-	-	-	-	1
Prepaid Domestic	-	-	-	-	-	-	-	-	-	-	-
Time Of Use	25,189	17,745	27,198	-	-	-	-	459	49,287	-	-
Streetlights	-	-	-	-	-	-	232	-	-	-	-
Major Customer A	-	-	-	-	-	-	-	-	-	-	-
Major Customer B	-	-	-	-	-	-	-	-	-	-	-
Major Customer C	-	-	-	-	-	-	-	-	-	-	-
Standard consumer totals	25,189	17,745	27,198	300,326	296	77,921	232	3,424	53,682	–	4
Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–	–
Total for all consumers	25,189	17,745	27,198	300,326	296	77,921	232	3,424	53,682	–	4

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	-	221	-	–	18	-	39	-	-	2,086	-
3 Rate	-	1,405	-	-	1,128	-	-	-	-	26	-
Standard Domestic	-	-	-	–	-	-	835	-	-	5,358	-
Low User Domestic	-	-	-	–	-	-	501	-	-	4,063	-
Prepaid Domestic	3,332	-	-	-	-	-	-	-	-	-	-
Time Of Use	-	310	-	-	236	-	-	388	6,522	-	5
Streetlights	-	-	1,623	-	-	-	-	-	-	-	-
Major Customer A	-	-	-	-	-	39,762	-	-	-	-	-
Major Customer B	-	-	-	-	-	15,478	-	-	-	-	-
Major Customer C	-	-	-	-	-	14,243	-	-	-	-	-
Standard consumer totals	3,332	1,936	1,623	–	1,382	–	1,375	388	6,522	11,533	5
Non-standard consumer totals	–	–	–	–	–	69,483	–	–	–	–	–
Total for all consumers	3,332	1,936	1,623	–	1,382	69,483	1,375	388	6,522	11,533	5

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	$11,670	$1,344	$11,670	
3 Rate	Commercial	Standard	$673	$77	$673	
Standard Domestic	Residential	Standard	$19,566	$2,253	$19,566	
Low User Domestic	Residential	Standard	$8,587	$989	$8,587	
Prepaid Domestic	Residential	Standard	$322	$37	$322	
Time Of Use	Commercial	Standard	$8,153	$939	$8,153	
Streetlights	Commercial	Standard	$497	$57	$497	
Major Customer A	Industrial	Non-standard	$1,437	$165	$1,437	
Major Customer B	Industrial	Non-standard	$731	$84	$731	
Major Customer C	Industrial	Non-standard	$480	$55	$480	
Add extra rows for additional consumer groups or price category codes as necessary						
		Standard consumer totals	$49,468	$5,695	$49,468	–
		Non-standard consumer totals	$2,648	$305	$2,648	–
		Total for all consumers	$52,116	$6,000	$52,116	–

Line charge revenues ($000) by price component

Price 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	-	-	-	$9,065	$14	$337	-	$60	$30	-	-
3 Rate	-	-	-	$8	-	$9	-	$51	$278	-	-
Standard Domestic	-	-	-	$13,102	-	$2,146	-	-	-	-	-
Low User Domestic	-	-	-	$6,378	-	$1,500	-	-	-	-	-
Prepaid Domestic	-	-	-	-	-	-	-	-	-	-	-
Time Of Use	$1,012	$1,105	$315	-	-	-	-	$11	$928	-	-
Streetlights	-	-	-	-	-	-	$22	-	-	-	-
Major Customer A	-	-	-	-	-	-	-	-	-	-	-
Major Customer B	-	-	-	-	-	-	-	-	-	-	-
Major Customer C	-	-	-	-	-	-	-	-	-	-	-
Add extra rows for additional consumer groups or price category codes as necessary	1,012	1,105	315	28,556	14	3,991	22	122	1,237	-	0
Standard consumer totals	$1,012	$1,105	$315	$28,553	$14	$3,992	$22	$122	$1,236	–	–
Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–	–
Total for all consumers	$1,012	$1,105	$315	$28,553	$14	$3,992	$22	$122	$1,236	–	–

Price 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	-	$21	-	-	$2	-	-	-	-	$2,141	-
3 Rate	-	$122	-	-	$176	-	-	-	-	$29	-
Standard Domestic	-	-	-	-	-	-	$8	-	-	$4,310	-
Low User Domestic	-	-	-	-	-	-	$5	-	-	$704	-
Prepaid Domestic	$322	-	-	-	-	-	-	-	-	-	-
Time Of Use	-	$29	-	-	$39	-	-	$3,670	$324	-	$720
Streetlights	-	-	$475	-	-	-	-	-	-	-	-
Major Customer A	-	-	-	-	-	$1,437	-	-	-	-	-
Major Customer B	-	-	-	-	-	$731	-	-	-	-	-
Major Customer C	-	-	-	-	-	$480	-	-	-	-	-
Add extra rows for additional consumer groups or price category codes as necessary	322	172	475	0	217	2,647	13	3,671	324	7,183	720
Standard consumer totals	$322	$172	$475	–	$217	–	$13	$3,670	$324	$7,184	$720
Non-standard consumer totals	–	–	–	–	–	$2,648	–	–	–	–	–
Total for all consumers	$322	$172	$475	–	$217	$2,648	$13	$3,670	$324	$7,184	$720

Check: OK

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	7

Company Name	**Counties Power Limited**
For Year Ended	**31 March 2019**
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

	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
8								
9	All	Overhead Line	Concrete poles / steel structure	No.	26,097	26,085	(12)	3
10	All	Overhead Line	Wood poles	No.	1,881	1,854	(27)	3
11	All	Overhead Line	Other pole types	No.	5	5	–	3
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	87	75	(13)	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	72	64	(8)	4
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	2	1	(1)	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.	–	–	–	4
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	29	29	–	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.	80	80	–	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.	15	15	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1,447	1,458	11	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	202	207	5	3
39	HV	Distribution Cable	Distribution UG PILC	km	21	21	(0)	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.	149	174	25	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.	4,916	4,894	(22)	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.	209	222	13	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	3,144	3,151	7	3
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	850	871	21	3
48	HV	Distribution Transformer	Voltage regulators	No.	4	4	–	3
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	842	869	27	3
50	LV	LV Line	LV OH Conductor	km	735	729	(7)	3
51	LV	LV Cable	LV UG Cable	km	666	695	29	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	47	48	1	3
53	LV	Connections	OH/UG consumer service connections	No.	42,078	42,923	845	3
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	144	144	–	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	3,547	3,469	(78)	3
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

Company Name	**Counties Power Limited**
For Year Ended	**31 March 2019**
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 2019

Number of assets at disclosure year end by installation date

sch ref	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	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.	26	21	212	2,181	3,452	6,211	6,572	249	713	374	271	354	337	452	326	412	547	312	331	252	135	236	129	118	1,294	540	28	–	26,085	–	3
11	All	Overhead Line	Wood poles	No.	–	1	6	43	112	92	473	27	11	9	–	5	4	5	2	5	11	3	5	6	2	7	6	4	867	148	–	–	1,854	–	3
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	5	–	–	–	–	–	–	5	–	3
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	3	–	–	18	30	7	–	–	–	–	–	14	–	2	–	–	–	–	0	–	–	–	–	–	1	–	–	–	75	–	4
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	0	18	–	6	–	–	–	–	24	–	–	–	–	–	–	–	10	5	–	–	–	–	–	64	–	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	–	0	–	–	–	–	–	0	0	–	0	0	–	–	0	–	–	–	–	–	–	–	–	–	1	–	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	–	–	–	–	–	–	–	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	76	226	217	311	261	19	19	29	17	9	11	25	13	8	27	18	13	11	8	10	7	8	9	26	2	–	1,458	–	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	12	2	9	14	9	9	10	16	17	9	13	7	0	–	207	–	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 sectionaliser	No.	–	–	–	–	1	12	9	3	3	1	–	–	4	3	5	4	8	9	2	9	10	11	2	6	34	36	2	–	174	–	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.	–	1	19	62	204	497	1,185	205	166	112	121	101	145	59	138	88	98	242	244	201	270	163	161	136	109	162	5	–	4,894	–	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	5	10	15	6	2	1	8	2	–	8	8	8	13	11	9	14	7	18	12	13	27	18	1	–	222	–	3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	8	1	72	81	211	413	710	115	76	117	139	81	38	101	40	73	102	63	189	89	155	118	21	59	29	50	–	–	3,151	–	3
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	2	–	5	17	21	30	182	40	30	21	41	16	25	42	28	23	31	25	37	25	59	45	30	59	30	6	1	–	871	–	3
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	1	–	–	1	–	–	–	–	1	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	4	–	3
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	5	9	33	144	27	19	20	27	22	28	29	27	31	20	40	47	30	65	49	44	41	60	48	4	–	869	–	3
51	LV	LV Line	LV OH Conductor	km	–	–	1	2	3	4	666	6	4	6	3	2	3	2	1	3	4	1	5	2	2	2	1	1	1	2	1	–	729	–	3
52	LV	LV Cable	LV UG Cable	km	–	–	0	1	8	4	225	23	18	20	16	15	34	41	22	14	7	20	12	21	17	38	28	33	41	35	1	–	695	–	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	0	48	–	3
54	LV	Connections	OH/UG consumer service connections	No.	–	–	–	1	–	11,789	14,198	1,114	532	595	884	976	1,003	842	877	884	602	589	503	497	683	891	869	1,243	1,225	986	1,051	89	42,923	–	3
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	4	16	10	17	2	–	–	–	–	–	–	15	–	–	–	–	4	9	–	17	37	–	12	–	1	–	144	–	3
56	All	SCADA and communications	SCADA and communications equipment operating as a single sys	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	2	1	3	1	7	4	2	86	1,159	1,010	41	1	2	–	–	3,469	–	3
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A

Company Name	**Counties Power Limited**
For Year Ended	**31 March 2019**
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	64	–	64
12	50kV & 66kV	–	–	–
13	33kV	75	1	76
14	SWER (all SWER voltages)	–	–	–
15	22kV (other than SWER)	574	154	727
16	6.6kV to 11kV (inclusive—other than SWER)	884	76	960
17	Low voltage (< 1kV)	729	695	1,424
18	**Total circuit length (for supply)**	2,326	926	3,251
19				
20	Dedicated street lighting circuit length (km)	0	48	48
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			8
22				

sch ref			
23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**
24	Urban	95	4%
25	Rural	2,146	92%
26	Remote only	–	–
27	Rugged only	85	4%
28	Remote and rugged	–	–
29	Unallocated overhead lines	–	–
30	**Total overhead length**	2,326	100%
31			
32		**Circuit length (km)**	**(% of total circuit length)**
33	Length of circuit within 10km of coastline or geothermal areas (where known)	1,468	45%
34		**Circuit length (km)**	**(% of total overhead length)**
35	Overhead circuit requiring vegetation management	2,326	100%

Company Name	**Counties Power Limited**
For Year Ended	**31 March 2019**

SCHEDULE 9d: REPORT ON EMBEDDED NETWORKS

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

sch ref			
8	**Location ***	**Number of ICPs served**	**Line charge revenue ($000)**
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 2019**
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

sch ref			
9	*Number of ICPs connected in year by consumer type*		
10	*Consumer types defined by EDB**	**Number of connections (ICPs)**	
11	Urban Residential	446	
12	Urban Commercial	174	
13	Rural Residential	295	
14	Rural Commercial	169	
15			
16	** include additional rows if needed*		
17	**Connections total**	1,084	
18			
19	**Distributed generation**		
20	Number of connections made in year	127	**connections**
21	Capacity of distributed generation installed in year	0.62	**MVA**

22 9e(ii): System Demand

sch ref				
23				
24				
25		**Maximum coincident system demand**	**Demand at time of maximum coincident demand (MW)**	
26		GXP demand	119	
27	*plus*	Distributed generation output at HV and above	9	
28		**Maximum coincident system demand**	128	
29	*less*	Net transfers to (from) other EDBs at HV and above		
30		**Demand on system for supply to consumers' connection points**	128	
31		**Electricity volumes carried**	**Energy (GWh)**	
32		Electricity supplied from GXPs	562	
33	*less*	Electricity exports to GXPs	–	
34	*plus*	Electricity supplied from distributed generation	50	
35	*less*	Net electricity supplied to (from) other EDBs		
36		**Electricity entering system for supply to consumers' connection points**	612	
37	*less*	Total energy delivered to ICPs	584	
38		**Electricity losses (loss ratio)**	28	4.6%
39				
40		**Load factor**	0.54	

41 9e(iii): Transformer Capacity

sch ref		
42		**(MVA)**
43	Distribution transformer capacity (EDB owned)	356
44	Distribution transformer capacity (Non-EDB owned, estimated)	55
45	**Total distribution transformer capacity**	410
46		
47	**Zone substation transformer capacity**	428

Company Name	**Counties Power Limited**
For Year Ended	**31 March 2019**
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

8 10(i): Interruptions

sch ref	Interruptions by class	Number of interruptions
10	Class A (planned interruptions by Transpower)	
11	Class B (planned interruptions on the network)	406
12	Class C (unplanned interruptions on the network)	305
13	Class D (unplanned interruptions by Transpower)	
14	Class E (unplanned interruptions of EDB owned generation)	
15	Class F (unplanned interruptions of generation owned by others)	
16	Class G (unplanned interruptions caused by another disclosing entity)	
17	Class H (planned interruptions caused by another disclosing entity)	
18	Class I (interruptions caused by parties not included above)	
19	**Total**	711

sch ref	Interruption restoration	≤3Hrs	>3hrs
22	Class C interruptions restored within	186	119

sch ref	SAIFI and SAIDI by class	SAIFI	SAIDI
25	Class A (planned interruptions by Transpower)		
26	Class B (planned interruptions on the network)	0.77	227.8
27	Class C (unplanned interruptions on the network)	3.20	364.9
28	Class D (unplanned interruptions by Transpower)		
29	Class E (unplanned interruptions of EDB owned generation)		
30	Class F (unplanned interruptions of generation owned by others)		
31	Class G (unplanned interruptions caused by another disclosing entity)		
32	Class H (planned interruptions caused by another disclosing entity)		
33	Class I (interruptions caused by parties not included above)		
34	**Total**	3.97	592.7

sch ref	Normalised SAIFI and SAIDI	Normalised SAIFI	Normalised SAIDI
37	Classes B & C (interruptions on the network)	3.97	397.7

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

sch ref	Cause	SAIFI	SAIDI
42	Lightning	0.19	5.8
43	Vegetation	0.69	219.1
44	Adverse weather		
45	Adverse environment		
46	Third party interference	0.25	29.3
47	Wildlife	0.50	11.6
48	Human error	0.09	7.1
49	Defective equipment	1.12	77.3
50	Cause unknown	0.36	14.7

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

sch ref	Main equipment involved	SAIFI	SAIDI
55	Subtransmission lines	0.01	1.0
56	Subtransmission cables		
57	Subtransmission other	0.01	0.5
58	Distribution lines (excluding LV)	0.65	196.0
69	Distribution cables (excluding LV)	0.10	30.3
60	Distribution other (excluding LV)		

Company Name	**Counties Power Limited**
For Year Ended	**31 March 2019**
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.

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

62

63	**Main equipment involved**	**SAIFI**	**SAIDI**
64	Subtransmission lines	0.27	49.8
65	Subtransmission cables	0.18	5.8
66	Subtransmission other	0.30	12.3
67	Distribution lines (excluding LV)	2.34	293.4
68	Distribution cables (excluding LV)	0.11	3.5
69	Distribution other (excluding LV)	–	0.1

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

71	**Main equipment involved**	**Number of Faults**	**Circuit length (km)**	**Fault rate (faults per 100km)**
72	Subtransmission lines	7	139	5.04
73	Subtransmission cables	1	1	90.91
74	Subtransmission other	5		
75	Distribution lines (excluding LV)	288	1,458	19.75
76	Distribution cables (excluding LV)	3	230	1.30
77	Distribution other (excluding LV)	1		
78	**Total**	305		

Company Name	Counties Power Limited
For Year Ended	31 March 2019

Schedule 14 Mandatory Explanatory Notes

(Guidance Note: This Microsoft Word version of Schedules 14, 14a and 15 is from the Electricity Distribution Information Disclosure Determination 2012 – as amended and consolidated 3 April 2018. Clause references in this template are to that determination)

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

2. This schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.1. Information provided in boxes 1 to 11 of this schedule is part of the audited disclosure information, and so is subject to the assurance requirements specified in section 2.8.

3. Schedule 15 (Voluntary Explanatory Notes to Schedules) provides for EDBs to give additional explanation of disclosed information should they elect to do so.

Return on Investment (Schedule 2)

4. In the box below, comment on return on investment as disclosed in Schedule 2. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

Box 1: Explanatory comment on return on investment

Classification is consistent with previous treatment.

ROI comparable to a post tax WACC decreased from 7.0% in FY18 to 6.4% in FY19 with the following items of note:

- Gross Line Revenue (before posted discount) increased by 3.5% in FY19. However net revenue was static due to an additional $2m discount posted in FY19 ($4m to $6m);

- Operational costs increased from 25% of lines revenue in FY18 to 28% of lines revenue this year to address high network growth and targeted improvements in reliability and the customer experience. This resulted in investments in the areas of Network support, IT and customer relationship management.

Recoverable costs reduced by $0.2m or 1.6% from the prior year.

CPI increased from 1.10% in FY18 to 1.48% this year.

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). 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
On 1 February 2019, Counties Power Limited acquired 75% of the issued share capital of ECL Group Limited, a leading technical services company specialising in fuel systems and technology solutions in New Zealand. This acquisition and related costs are not included in the Regulatory business.

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 RAB classifications from the prior year. For non-network assets that were not directly attributable, the allocation methodology used for FY19 was ABAA with Proxy allocators used. The adjustment to the RAB for this change was $592k. Assets being disposed of comprise non-system minor plant and equipment ($22k) and transformers sold as scrap ($70k). A loss of $43k was recorded for these disposals.

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 - $6k and entertainment expense - $25k). 8.3 Income included in regulatory profit before tax but not taxable (Nil).

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 ($30k @28% = $8k). Holiday leave provision - $314k (FY18 - $263k) Other leave provisions - $105k (FY18 - $152k) Doubtful debt provision - $335k (FY18 - $309k)

Cost allocation (Schedule 5d)

10. In the box below, comment on cost allocation as disclosed in Schedule 5d. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

Box 7: Cost allocation

Cost allocations were calculated using ABAA methodology as per the IM Determination for business support. In particular:

• Property identified space usage as the proxy allocator; and

• Finance, IT and Corporate costs allocated costs using resource as the proxy allocator.

Proxy allocators were used as causal relationships could not be reasonably established. Property costs were allocated as a proportion of space used. IT, Finance and Corporate costs were allocated based on the level of resource allocated to the regulated business.

Asset allocation (Schedule 5e)

11. In the box below, comment on asset allocation as disclosed in Schedule 5e. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

Box 8: Commentary on asset allocation

Asset allocations were calculated using ABAA methodology as per the IM Determination.

In particular:

• Property identified space usage as the proxy allocator where costs could not be directly allocated; and

• Finance, IT and Corporate costs used resource as the proxy allocator.

An adjustment resulting from asset allocation of $592k has been calculated in schedule 5e (0.2% adjustment to the closing RAB) to conform with ABAA methodology.

No other items have been reclassified during the disclosure year.

Capital Expenditure for the Disclosure Year (Schedule 6a)

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

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

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

Box 9: Explanation of capital expenditure for the disclosure year

13.1: Consumer types are based on historical AMP descriptions. Treatment for all other categories was to sum the many small projects by significant core drivers.

13.2: Classification is consistent with treatment in prior years.

Operational Expenditure for the Disclosure Year (Schedule 6b)

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

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

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

    13.3 Commentary on any material atypical expenditure included in operational expenditure disclosed in Schedule 6b, a including the value of the expenditure the purpose of the expenditure, and the operational expenditure categories the expenditure relates to.

Box 10: Explanation of operational expenditure for the disclosure year

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)

14. In the box below, comment on variance in actual to forecast expenditure for the disclosure year, as reported in Schedule 7. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

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

7(i): The favourable variance reflects continued high ICP growth and strong industrial volumes.

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

- System Growth (22% above target) reflects an accelerated level of growth on the network;
- Asset replacement and renewal was 17% below forecast and driven in large part by efficiencies as the work schedule was completed;
- Asset relocations were lower than target due to the deferral of the 110kV line relocation for Drury South to FY20;
- Quality of supply was 38% below forecast with 3 voltage regulator projects deferred to FY20;

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

- Network operational items that finished below budget can be attributed to operational efficiencies. The budgeted work schedule was completed.
- Higher business support reflects investments in the areas of Network support, IT and customer relationship management.

Information relating to revenues and quantities for the disclosure year

15. In the box below provide-

    15.1 a comparison of the target revenue disclosed before the start of the disclosure year, in accordance with clause 2.4.1 and subclause 2.4.3(3) to total billed line charge revenue for the disclosure year, as disclosed in Schedule 8; and

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

Box 12: Explanatory comment relating to revenue for the disclosure year

Total billed line charge revenue was $52.1m against a target of $51.3m.

The higher actual billed line charge revenue reflects strong volumes from industrial customers and continued high ICP growth.

Network Reliability for the Disclosure Year (Schedule 10)

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

Box 13: Commentary on network reliability for the disclosure year

Unplanned outages, as measured by SAIDI, exceeded the target by 37% in FY19. Contributing factors to the unfavourable result included an increase in severe weather events affecting the network and in particular the April 2018 storm event. The main fault causes were overhead equipment failure, vegetation and a high number of vehicle vs pole incidents.

Planned SAIDI was 20% unfavourable to target in FY19. 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 where faults affected large groups of customers in single events, as well as repeat outages on some highly populated feeders.

Refer also to the commentary provided in Box 1 of Schedule 15 regarding the SAIFI calculation.

Insurance cover

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

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

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

Box 14: Explanation of insurance cover

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

18. In the box below, provide information about amendments to previously disclosed information disclosed in accordance with clause 2.12.1 in the last 7 years, including:

18.1 a description of each error; and

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

Box 15: Disclosure of amendment to previously disclosed information
There have been no material amendments to previously disclosed information pursuant to clause 2.12.1 disclosed in the last 9 years.

Company Name	Counties Power Limited
For Year Ended	31 March 2019

Schedule 14a Mandatory Explanatory Notes on Forecast Information

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

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

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

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

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

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts
The difference between nominal and constant prices reflects inflation of 1.5% 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 1.5% per annum.

Company Name	Counties Power Limited
For Year Ended	31 March 2019

Schedule 15 Voluntary Explanatory Notes

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

1. This schedule enables EDBs to provide, should they wish to-

    1.1 additional explanatory comment to reports prepared in accordance with clauses 2.3.1, 2.4.21, 2.4.22, 2.5.1 and 2.5.2;

    1.2 information on any substantial changes to information disclosed in relation to a prior disclosure year, as a result of final wash-ups.

2. Information in this schedule is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

3. Provide additional explanatory comment in the box below.

Box 1: Voluntary explanatory comment on disclosed information

Consistent with prior years Counties Power has interpreted a customer interruption on an overall outage event basis. Therefore, if a customer was interrupted multiple times for longer than a minute as a consequence of sectionalising and fault finding, then the customer was only recorded as being interrupted once rather than counting customer interruptions by stage within that outage event.

Concerns have recently been raised around the consistent interpretation of a customer interruption within the industry with further clarity requested from the Commerce Commission. For consistency with our targets and prior years we have reported the information in Schedule 10 in line with our interpretation as outlined above. However, we have also recalculated SAIFI based on the alternative interpretation and note SAIFI for FY19 would increase by 10% from 3.97 to 4.37 and Normalised SAIFI by 2% from 3.97 to 4.06.

As noted in Schedule 14, SAIFI performance was unfavourable to target due to the nature of unplanned outages where faults affected large groups of customers in single events, as well as repeat outages on some highly populated feeders. Contributing factors to the unfavourable result included an increase in severe weather events affecting the network and in particular the April 2018 storm event. The main fault causes were overhead equipment failure, vegetation and a high number of vehicle vs pole incidents.

Following is a table providing a comparison of Schedule 10 to the alternative interpretation:

	Schedule 10 (as Reported)	Alternative Interpretation	Variance
10(i): Interruptions			
Interruptions by class		**Number of Interruptions**	
Class B (planned interruptions on the network)	406	417	11
Class C (unplanned interruptions on the network)	305	341	36
Total	**711**	**758**	**47**
Interruption restoration		**≤3Hrs**	
Class C interruptions restored within	**186**	**222**	**36**
SAIFI by class		**SAIFI**	
Class B (planned interruptions on the network)	0.77	0.79	0.02
Class C (unplanned interruptions on the network)	3.20	3.58	0.38
Total	**3.97**	**4.37**	**0.40**
		Normalised SAIFI	
Classes B & C (interruptions on the network)	**3.97**	**4.06**	**0.09**
10(ii): Class C Interruptions by Cause		**SAIFI**	
Lightning	0.19	0.20	0.01
Vegetation	0.69	1.00	0.31
Third party interference	0.25	0.25	-
Wildlife	0.50	0.50	-
Human error	0.09	0.09	-
Defective equipment	1.12	1.18	0.06
Cause unknown	0.36	0.36	-
Total	**3.20**	**3.58**	**0.38**
10(iii): Class B Interruptions by Main Equipment Involved		**SAIFI**	
Subtransmission lines	0.01	0.01	-
Subtransmission other	0.01	0.01	-
Distribution lines (excluding LV)	0.65	0.67	0.02
Distribution cables (excluding LV)	0.10	0.10	-
Total	**0.77**	**0.79**	**0.02**
10(iv): Class C Interruptions by Main Equipment Involved		**SAIFI**	
Subtransmission lines	0.27	0.27	-
Subtransmission cables	0.18	0.18	-
Subtransmission other	0.30	0.30	-
Distribution lines (excluding LV)	2.34	2.72	0.38
Distribution cables (excluding LV)	0.11	0.11	-
Total	**3.20**	**3.58**	**0.38**
10(v): Fault Rate - Main Equipment Involved		**Number of Faults**	
Subtransmission lines	7	7	-
Subtransmission cables	1	1	-
Subtransmission other	5	5	-
Distribution lines (excluding LV)	288	324	36
Distribution cables (excluding LV)	3	3	-
Distribution other (excluding LV)	1	1	-
Total	**305**	**341**	**36**

COUNTIESPOWER

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, 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;

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; and

c) in respect of information concerning assets, costs and revenues valued or disclosed in accordance with clause 2.3.6 of the Electricity Distribution Information Disclosure Determination 2012 and clauses 2.2.11(1)(g) and 2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012, we are satisfied that -

   i. the costs and values of assets or goods or services acquired from a related party comply, in all material respects, with clauses 2.3.6(1) and 2.3.6(3) of the Electricity Distribution Information Disclosure Determination 2012 and clauses 2.2.11(1)(g) and 2.2.11(5)(a)-2.2.11(5)(b) of the Electricity Distribution Services Input Methodologies Determination 2012; and

   ii. the value of assets or goods or services sold or supplied to a related party comply, in all material respects, with clause 2.3.6(2) of the Electricity Distribution Information Disclosure Determination 2012.

DJ Troon
26 August 2019

HW Stevens
26 August 2019

Independent Assurance Report

To the Directors of Counties Power Limited and the Commerce Commission

Assurance Report Pursuant to Electricity Distribution Information Disclosure Determination 2012

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 required to be disclosed in accordance with the Electricity Distribution Information Disclosure Determination 2012 ('the Information Disclosure Determination') for the disclosure year ended 31 March 2019, has been prepared, in all material respects, in accordance with the Information Disclosure Determination.
- The disclosure information required to be reported by the Company, and audited by the Auditor-General, under the Information Disclosure Determination is in schedules 1 to 4, 5a to 5g, 6a and 6b, 7, and the explanatory notes in boxes 1 to 11 in Schedule 14 ('the Disclosure Information').
- whether the Company's basis for valuation of related party transactions ('the Related Party Transaction Information') for the disclosure year ended 31 March 2019, has been prepared, in all material respects, in accordance with clause 2.3.6 of the Information Disclosure Determination, and clauses 2.2.11(1)(g) and 2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012 ('the Input Methodologies Determination').

Opinion

In our opinion:

- as far as appears from an examination of them, proper records to enable the complete and accurate compilation of the Disclosure Information have been kept by the Company;
- as far as appears from an examination, the information used in the preparation of the Disclosure Information has been properly extracted from the Company's accounting and other records and has been sourced, where appropriate, from the Company's financial and non-financial systems;
- the Disclosure Information complies, in all material respects, with the Information Disclosure Determination; and
- the Related Party Transaction Information complies, in all material respects, with the Information Disclosure Determination and the Input Methodologies Determination.

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

Basis for opinion

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

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

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

Scope and inherent limitations

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

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

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

Key Assurance Matters

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

Key assurance matter	*How our procedures addressed the key assurance matter*
Regulatory Asset Base The Regulatory Asset Base (RAB), as set out in Schedule 4, reflects the value of the Company's electricity distribution assets. These are valued using an indexed historic cost methodology prescribed by the Determination. It is a measure which is used widely and is key to measuring the Company's return on investment and therefore important when monitoring financial performance or setting electricity distribution prices. The RAB inputs, as set out in the Input Methodologies, are similar to those used in the measurement of property, plant and equipment in the financial statements, however, there are a number of different requirements and complexities which require careful consideration. Due to the importance of the RAB within the regulatory regime, the incentives to overstate the RAB value, and complexities within the regulations, we have considered it to be a key area of focus.	We have obtained an understanding of the compliance requirements relevant to the RAB as set out in the Information Disclosure Determination (ID Determination) and the Input Methodologies (IMs). We have performed the following procedures: *Assets commissioned* • We reconciled the assets commissioned as per the regulatory fixed asset register to the asset additions disclosed in the audited annual financial statements, and investigated any reconciling items; • We inspected the assets commissioned during the period, as per the regulatory fixed asset register, to identify any specific cost or asset type exclusions, as set out in the ID Determination, which are required to be removed from the RAB; • We tested a sample of assets commissioned during the disclosure period for appropriate asset category classification; *Depreciation* • We compared the standard asset lives by asset category to those set out in the IMs; • For assets with no standard asset lives we assessed the reasonableness of the lives used by reference to the accounting depreciation rates; • We tested the mathematical accuracy of the depreciation calculation on a sample basis and that it is performed in line with IM clause 2.2.5; *Revaluation* • We recalculated the revaluation rate set out in the Input Methodologies using the relevant Consumer Price Index indices taken from the Statistics New Zealand website; • We tested the mathematical accuracy of the revaluation calculation performed by management; *Disposals* • We inspected the asset disposals within the accounting fixed asset register to ensure disposals in the RAB meet the definition of a disposal per the IMs; We have no matters to report from undertaking those procedures.

Key assurance matter	*How our procedures addressed the key assurance matter*
Cost and Asset Allocation The ID Determination relates to information concerning the supply of electricity distribution services. In addition to the regulated supply of electricity, Counties Power Limited also supplies customers with other unregulated services such as external contracting, metering and fibre services. As set out in schedules 5d, 5e, 5f and 5g, costs and asset values that relate to electricity distribution services regulated under the ID Determination should comprise: • all of the costs directly attributable to the regulated goods or services; and • an allocated portion of the costs that are not directly attributable. The IMs set out rules and processes for allocating costs and assets which are not directly attributable to either regulated or unregulated services. A number of screening tests apply which must be considered when deciding on the appropriate allocation method. The Company has applied the Accounting-Based Allocation Approach Methodology (ABAA) utilising proxy cost and asset allocators to allocate the asset values and operating costs that are not directly attributable where causal relationships could not be identified. Given the judgement involved in the application of the cost and asset allocation methodologies we consider it a key assurance matter.	We obtained an understanding of the Company's cost and asset allocation processes and the methodologies applied. Our procedures over cost and asset allocation included: • Reconciling the regulated and unregulated financial information to the audited financial statements; *Classification as directly/not directly attributable* • Considering the appropriateness of the costs allocated as directly attributable, based on the nature and our understanding of the business to determine the reasonableness of the directly attributable classification; • Testing a sample of invoices to ensure their classification as either directly attributable or not directly attributable costs are appropriate and in line with the ID determination; • Inspecting the fixed asset register to identify any asset classes which based on their nature and our understanding of the business could be considered assets directly attributable to a specific business unit; • Testing a sample of assets commissioned to ensure their classification as either directly attributable or not directly attributable are appropriate and in line with the ID determination by inspecting the related invoice; *Appropriateness of the allocators used for not directly attributable costs and assets* • Understanding why causal relationships could not be identified in allocating costs or assets and ensuring appropriate disclosure has been included outlining these in Schedule 14; • Considering the appropriateness of the cost and asset proxy allocators used in applying ABAA to not directly attributable costs including surveying a sample of staff to understand their role and allocation of time; • Recalculating the split between not directly attributable costs and asset values allocated to electricity distribution services and non-electricity distribution services. We have no matters to report from undertaking those procedures.

Directors' responsibility for the preparation of the Disclosure Information and the related party information

The Directors of the Company are responsible for:

- the preparation of the Disclosure Information in accordance with the Information Disclosure Determination, and
- the Related Party Transaction Information in accordance with the Information Disclosure Determination and the Input Methodologies Determination

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

Our responsibility for the audit of the Disclosure Information and the related party information

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

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

Independence and quality control

When carrying out the engagement, we complied with:

- the Auditor-General's independence and other ethical requirements, which incorporate the independence and ethical requirements of Professional and Ethical Standard 1 (Revised) issued by the New Zealand Auditing and Assurance Standards Board;
- the independence requirements specified in the Information Disclosure Determination; and
- the Auditor-General's quality control requirements, which incorporate the quality control requirements of Professional and Ethical Standard 3 (Amended) issued by the New Zealand Auditing and Assurance Standards Board.

The Auditor-General, and his employees, and PricewaterhouseCoopers and its partners and employees may deal with the Company on normal terms within the ordinary course of trading activities of the Company. In addition to this engagement, we have performed the annual audit, provided regulatory compliance advice and other advisory services to the Company. These assignments were compatible with the Auditor General's independence requirements. Other than the provision of these assignments, we have no relationship or interests in the Company.

Use of this report

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

Mark Bramley
PricewaterhouseCoopers
On behalf of the Auditor-General
Auckland, New Zealand
28 August 2019