COUNTIESPOWER

Information Disclosure prepared in accordance with the

Electricity Distribution Information Disclosure Determination 2012

For the Year Ended 31 March 2020

Contents

1. Current Year Schedules

Company Name	**Counties Power Limited**
For Year Ended	**31 March 2020**

SCHEDULE 1: ANALYTICAL RATIOS

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

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

sch ref

1(i): Expenditure metrics

	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)
Operational expenditure	25,487	362	122,003	4,672	36,522
Network	7,641	109	36,575	1,401	10,949
Non-network	17,847	253	85,428	3,271	25,573
Expenditure on assets	87,056	1,236	416,723	15,957	124,747
Network	81,982	1,164	392,432	15,027	117,476
Non-network	5,074	72	24,291	930	7,271

1(ii): Revenue metrics

	Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
Total consumer line charge revenue	83,715	1,189
Standard consumer line charge revenue	96,909	1,129
Non-standard consumer line charge revenue	23,428	288,667

1(iii): Service intensity measures

Demand density	38	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
Volume density	183	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
Connection point density	13	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
Energy intensity	14,202	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*

1(iv): Composition of regulatory income

	($000)	% of revenue
Operational expenditure	15,741	30.37%
Pass-through and recoverable costs excluding financial incentives and wash-ups	14,507	27.99%
Total depreciation	9,353	18.05%
Total revaluations	6,847	13.21%
Regulatory tax allowance	2,747	5.30%
Regulatory profit/(loss) including financial incentives and wash-ups	16,332	31.51%
Total regulatory income	51,833	

1(v): Reliability

Interruption rate	19.83	*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 18**	**31 Mar 19**	**31 Mar 20**
9	**ROI – comparable to a post tax WACC**	**%**	**%**	**%**
10	Reflecting all revenue earned	7.04%	6.35%	5.88%
11	Excluding revenue earned from financial incentives	7.04%	6.35%	5.88%
12	Excluding revenue earned from financial incentives and wash-ups	7.04%	6.35%	5.88%
14	**Mid-point estimate of post tax WACC**	5.04%	4.75%	4.27%
15	25th percentile estimate	4.36%	4.07%	3.59%
16	75th percentile estimate	5.72%	5.43%	4.95%
19	**ROI – comparable to a vanilla WACC**			
20	Reflecting all revenue earned	7.63%	6.86%	6.31%
21	Excluding revenue earned from financial incentives	7.63%	6.86%	6.31%
22	Excluding revenue earned from financial incentives and wash-ups	7.63%	6.86%	6.31%
24	**WACC rate used to set regulatory price path**			
26	**Mid-point estimate of vanilla WACC**	5.60%	5.26%	4.69%
27	25th percentile estimate	4.92%	4.58%	4.01%
28	75th percentile estimate	6.29%	5.94%	5.37%

sch ref				
30	**2(ii): Information Supporting the ROI**		**($000)**	
32	Total opening RAB value	270,478		
33	*plus* Opening deferred tax	(15,659)		
34	**Opening RIV**		254,819	
36	**Line charge revenue**		51,702	
38	Expenses cash outflow	30,248		
39	*add* Assets commissioned	19,344		
40	*less* Asset disposals	42		
41	*add* Tax payments	998		
42	*less* Other regulated income	131		
43	**Mid-year net cash outflows**		50,417	
45	**Term credit spread differential allowance**		–	
47	Total closing RAB value	287,274		
48	*less* Adjustment resulting from asset allocation	0		
49	*less* Lost and found assets adjustment	–		
50	*plus* Closing deferred tax	(17,408)		
51	**Closing RIV**		269,866	
53	**ROI – comparable to a vanilla WACC**			6.31%
55	Leverage (%)			42%
56	Cost of debt assumption (%)			3.61%
57	Corporate tax rate (%)			28%
59	**ROI – comparable to a post tax WACC**			5.88%

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SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

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

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**	6.17%
96	**Year-end ROI – comparable to a post tax WACC**	5.75%

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**		–

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

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

sch ref				
7		**3(i): Regulatory Profit**		**($000)**
8		**Income**		
9		Line charge revenue		51,702
10	*plus*	Gains / (losses) on asset disposals		(40)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)		171
12				
13		**Total regulatory income**		51,833
14		**Expenses**		
15	*less*	Operational expenditure		15,741
16				
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups		14,507
18				
19		**Operating surplus / (deficit)**		21,585
20				
21	*less*	Total depreciation		9,353
22				
23	*plus*	Total revaluations		6,847
24				
25		**Regulatory profit / (loss) before tax**		19,079
26				
27	*less*	Term credit spread differential allowance		–
28				
29	*less*	Regulatory tax allowance		2,747
30				
31		**Regulatory profit/(loss) including financial incentives and wash-ups**		16,332
32				
33		**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	**($000)**	
34		**Pass through costs**		
35		Rates	730	
36		Commerce Act levies	79	
37		Industry levies	110	
38		CPP specified pass through costs		
39		**Recoverable costs excluding financial incentives and wash-ups**		
40		Electricity lines service charge payable to Transpower	12,727	
41		Transpower new investment contract charges	229	
42		System operator services		
43		Distributed generation allowance	632	
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**		14,507
47				

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SCHEDULE 3: REPORT ON REGULATORY PROFIT

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sch ref

sch ref				($000)	
48	**3(iii): Incremental Rolling Incentive Scheme**				
49				**CY-1**	**CY**
50				**31 Mar 19**	**31 Mar 20**
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 15		
58		CY-4	31 Mar 16		
59		CY-3	31 Mar 17		
60		CY-2	31 Mar 18		
61		CY-1	31 Mar 19		
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			

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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 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
	($000)	**($000)**	**($000)**	**($000)**	**($000)**
Total opening RAB value	228,249	231,077	241,528	253,205	270,478
less **Total depreciation**	7,623	7,690	7,899	8,228	9,353
plus **Total revaluations**	1,337	4,997	2,661	3,754	6,847
plus **Assets commissioned**	9,361	13,336	16,432	22,431	19,344
less **Asset disposals**	247	193	108	92	42
plus **Lost and found assets adjustment**					–
plus **Adjustment resulting from asset allocation**			593	(592)	0
Total closing RAB value	231,077	241,528	253,205	270,478	287,274

4(ii): Unallocated Regulatory Asset Base

	Unallocated RAB *		RAB	
	($000)	**($000)**	**($000)**	**($000)**
Total opening RAB value		271,355		270,478
less				
Total depreciation		9,396		9,353
plus				
Total revaluations		6,870		6,847
plus				
Assets commissioned (other than below)	19,449		19,344	
Assets acquired from a regulated supplier	–		–	
Assets acquired from a related party	–		–	
Assets commissioned		19,449		19,344
less				
Asset disposals (other than below)	44		42	
Asset disposals to a regulated supplier	–		–	
Asset disposals to a related party	–		–	
Asset disposals		44		42
plus **Lost and found assets adjustment**				
plus **Adjustment resulting from asset allocation**				0
Total closing RAB value		288,233		287,274

** 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	1,052
CPI_4^{-4}	1,026
Revaluation rate (%)	2.53%

	Unallocated RAB *		RAB	
	($000)	**($000)**	**($000)**	**($000)**
Total opening RAB value	271,355		270,478	
less Opening value of fully depreciated, disposed and lost assets	269		269	
Total opening RAB value subject to revaluation	271,086		270,209	
Total revaluations		6,870		6,847

4(iv): Roll Forward of Works Under Construction

	Unallocated works under construction		Allocated works under construction	
Works under construction—preceding disclosure year		5,171		5,171
plus Capital expenditure	45,751		45,647	
less Assets commissioned	19,449		19,344	
plus Adjustment resulting from asset allocation				
Works under construction - current disclosure year		31,474		31,474
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	8,066		8,066	
80	Depreciation - no standard life assets	1,330		1,288	
81	Depreciation - modified life assets				
82	Depreciation - alternative depreciation in accordance with CPP				
83	**Total depreciation**		9,396		9,353
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**	17,106	220	22,301	99,059	44,906	40,758	13,663	5,859	26,606	270,478
100	*less*	Total depreciation	446	8	681	2,581	1,477	1,513	774	488	1,385	9,353
101	*plus*	Total revaluations	434	6	565	2,510	1,138	1,032	345	148	669	6,847
102	*plus*	Assets commissioned	40	–	1,599	6,736	2,163	2,635	2,913	124	3,134	19,344
103	*less*	Asset disposals	–	–	–	–	–	36	–	–	6	42
104	*plus*	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
105	*plus*	Adjustment resulting from asset allocation	–	–	–	–	–	–	–	–	–	–
106	*plus*	Asset category transfers	–	–	–	–	–	–	–	–	–	–
107		**Total closing RAB value**	17,134	218	23,784	105,724	46,730	42,876	16,147	5,643	29,018	287,274
108												
109		**Asset Life**										
110		Weighted average remaining asset life	44.9	26.0	36.5	47.1	38.7	34.4	34.3	8.8	12.0	(years)
111		Weighted average expected total asset life	59.2	44.5	45.0	60.0	52.7	45.0	35.0	13.2	17.3	(years)

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SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

This schedule requires information on the calculation of the regulatory tax allowance. This information is used to calculate regulatory profit/loss in Schedule 3 (regulatory profit). EDBs must provide explanatory commentary on the information disclosed in this schedule, in Schedule 14 (Mandatory Explanatory Notes).
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 3.8

sch ref				
7		**5a(i): Regulatory Tax Allowance**		**($000)**
8		**Regulatory profit / (loss) before tax**		19,079
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	(14)	*
12		Amortisation of initial differences in asset values	2,663	
13		Amortisation of revaluations	885	
14				3,535
15				
16	*less*	Total revaluations	6,847	
17		Income included in regulatory profit / (loss) before tax but not taxable		*
18		Discretionary discounts and customer rebates	2,160	
19		Expenditure or loss deductible but not in regulatory profit / (loss) before tax		*
20		Notional deductible interest	3,796	
21				12,803
22				
23		**Regulatory taxable income**		9,811
24				
25	*less*	Utilised tax losses		
26		Regulatory net taxable income		9,811
27				
28		Corporate tax rate (%)	28%	
29		**Regulatory tax allowance**		2,747
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	71,911	
37	*less*	Amortisation of initial differences in asset values	2,663	
38	*plus*	Adjustment for unamortised initial differences in assets acquired		
39	*less*	Adjustment for unamortised initial differences in assets disposed	8	
40		Closing unamortised initial differences in asset values		69,240
41				
42		Opening weighted average remaining useful life of relevant assets (years)		27
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 3.8

sch ref				
44		**5a(iv): Amortisation of Revaluations**		**($000)**
45				
46		Opening sum of RAB values without revaluations	246,336	
47				
48		Adjusted depreciation	8,468	
49		Total depreciation	9,353	
50		Amortisation of revaluations		885
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**	(15,659)	
61				
62	*plus*	Tax effect of adjusted depreciation	2,371	
63				
64	*less*	Tax effect of tax depreciation	3,351	
65				
66	*plus*	Tax effect of other temporary differences*	(23)	
67				
68	*less*	Tax effect of amortisation of initial differences in asset values	746	
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	–	
73				
74	*plus*	Deferred tax cost allocation adjustment	(0)	
75				
76		**Closing deferred tax**		(17,408)
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**	120,149	
84	*less*	Tax depreciation	11,969	
85	*plus*	Regulatory tax asset value of assets commissioned	17,622	
86	*less*	Regulatory tax asset value of asset disposals	42	
87	*plus*	Lost and found assets adjustment		
88	*plus*	Adjustment resulting from asset allocation	–	
89	*plus*	Other adjustments to the RAB tax value		
90		**Closing sum of regulatory tax asset values**		125,760

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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

	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			

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SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

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

sch ref

7

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

9

sch ref	Issuing party	Issue date	Pricing date	Original tenor (in years)	Coupon rate (%)	Book value at issue date (NZD)	Book value at date of financial statements (NZD)	Term Credit Spread Difference	Debt issue cost readjustment
11	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 2020**

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref

5d(i): Operating Cost Allocations

	Value allocated ($000s)				
	Arm's length deduction	**Electricity distribution services**	**Non-electricity distribution services**	**Total**	**OVABAA allocation increase ($000s)**
Service interruptions and emergencies					
Directly attributable		2,038			
Not directly attributable				–	
Total attributable to regulated service		2,038			
Vegetation management					
Directly attributable		1,512			
Not directly attributable				–	
Total attributable to regulated service		1,512			
Routine and corrective maintenance and inspection					
Directly attributable		900			
Not directly attributable				–	
Total attributable to regulated service		900			
Asset replacement and renewal					
Directly attributable		269			
Not directly attributable				–	
Total attributable to regulated service		269			
System operations and network support					
Directly attributable		3,747			
Not directly attributable				–	
Total attributable to regulated service		3,747			
Business support					
Directly attributable		929			
Not directly attributable		6,346	1,083	7,429	
Total attributable to regulated service		7,275			
Operating costs directly attributable		9,395			
Operating costs not directly attributable	–	6,346	1,083	7,429	–
Operational expenditure		15,741			

5d(ii): Other Cost Allocations

Pass through and recoverable costs	**($000)**
Pass through costs	
Directly attributable	919
Not directly attributable	
Total attributable to regulated service	919
Recoverable costs	
Directly attributable	13,588
Not directly attributable	
Total attributable to regulated service	13,588

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

Change in cost allocation 1

			($000) CY-1	($000) 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	($000) 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	($000) 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 2020**

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	17,134
Not directly attributable	
Total attributable to regulated service	17,134
Subtransmission cables	
Directly attributable	218
Not directly attributable	
Total attributable to regulated service	218
Zone substations	
Directly attributable	23,784
Not directly attributable	
Total attributable to regulated service	23,784
Distribution and LV lines	
Directly attributable	105,724
Not directly attributable	
Total attributable to regulated service	105,724
Distribution and LV cables	
Directly attributable	46,730
Not directly attributable	
Total attributable to regulated service	46,730
Distribution substations and transformers	
Directly attributable	42,876
Not directly attributable	
Total attributable to regulated service	42,876
Distribution switchgear	
Directly attributable	16,147
Not directly attributable	
Total attributable to regulated service	16,147
Other network assets	
Directly attributable	5,643
Not directly attributable	
Total attributable to regulated service	5,643
Non-network assets	
Directly attributable	23,021
Not directly attributable	5,997
Total attributable to regulated service	29,018
Regulated service asset value directly attributable	281,277
Regulated service asset value not directly attributable	5,997
Total closing RAB value	287,274

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

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

			($000) CY-1	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	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 comp*
† include additional rows if needed

Company Name	**Counties Power Limited**
For Year Ended	**31 March 2020**

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		9,241
9		System growth		26,698
10		Asset replacement and renewal		12,537
11		Asset relocations		48
12		Reliability, safety and environment:		
13		Quality of supply	386	
14		Legislative and regulatory	1,722	
15		Other reliability, safety and environment	–	
16		**Total reliability, safety and environment**		2,108
17		**Expenditure on network assets**		50,632
18		Expenditure on non-network assets		3,134
19				
20		**Expenditure on assets**		53,766
21	*plus*	Cost of financing		297
22	*less*	Value of capital contributions		8,416
23	*plus*	Value of vested assets		
24				
25		**Capital expenditure**		45,647
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		5,862
29		Research and development		
30		**6a(iii): Consumer Connection**		
31		*Consumer types defined by EDB**	**($000)**	**($000)**
32		Urban residential	4,819	
33		Urban commercial	1,530	
34		Rural residential	2,076	
35		Rural commercial	816	
36				
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		9,241
39				
40	*less*	Capital contributions funding consumer connection expenditure	8,416	
41		**Consumer connection less capital contributions**		825
42		**6a(iv): System Growth and Asset Replacement and Renewal**		**Asset Replacement and**
43			**System Growth**	**Renewal**
44			**($000)**	**($000)**
45		Subtransmission	3	–
46		Zone substations	20,104	786
47		Distribution and LV lines	3,185	4,468
48		Distribution and LV cables	2,465	2,515
49		Distribution substations and transformers	872	593
50		Distribution switchgear	–	4,152
51		Other network assets	69	23
52		**System growth and asset replacement and renewal expenditure**	26,698	12,537
53	*less*	Capital contributions funding system growth and asset replacement and renewal		
54		**System growth and asset replacement and renewal less capital contributions**	26,698	12,537
55				
56		**6a(v): Asset Relocations**		
57		*Project or programme**	**($000)**	**($000)**
58		Various relocation (largely reimbursed by customers)	48	
59				
60				
61				
62				
63		** include additional rows if needed*		
64		All other projects or programmes - asset relocations	–	
65		**Asset relocations expenditure**		48
66	*less*	Capital contributions funding asset relocations		
67		**Asset relocations less capital contributions**		48
68				

Company Name	**Counties Power Limited**
For Year Ended	**31 March 2020**

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		Voltage upgrades (4 locations)	372	
72		Other projects	14	
73				
74				
75				
76		** include additional rows if needed*		
77		All other projects programmes - quality of supply	–	
78		**Quality of supply expenditure**		386
79	*less*	Capital contributions funding quality of supply	–	
80		**Quality of supply less capital contributions**		386
81	**6a(vii): Legislative and Regulatory**			
82		*Project or programme**	**($000)**	**($000)**
83		Right of use assets	1,722	
84				
85				
86				
87				
88		** include additional rows if needed*		
89		All other projects or programmes - legislative and regulatory		
90		**Legislative and regulatory expenditure**		1,722
91	*less*	Capital contributions funding legislative and regulatory		
92		**Legislative and regulatory less capital contributions**		1,722
93	**6a(viii): Other Reliability, Safety and Environment**			
94		*Project or programme**	**($000)**	**($000)**
95		Nil		
96				
97				
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**		–
103	*less*	Capital contributions funding other reliability, safety and environment		
104		**Other reliability, safety and environment less capital contributions**		–
105				
106	**6a(ix): Non-Network Assets**			
107		**Routine expenditure**		
108		*Project or programme**	**($000)**	**($000)**
109		IT software	1,880	
110		Building upgrades	410	
111		Vehicles	308	
112		Other plant and equipment	536	
113				
114		** include additional rows if needed*		
115		All other projects or programmes - routine expenditure		
116		**Routine expenditure**		3,134
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**		3,134

Company Name	**Counties Power Limited**
For Year Ended	**31 March 2020**

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	2,038	
9	Vegetation management	1,512	
10	Routine and corrective maintenance and inspection	900	
11	Asset replacement and renewal	269	
12	**Network opex**		4,719
13	System operations and network support	3,747	
14	Business support	7,275	
15	**Non-network opex**		11,022
16			
17	**Operational expenditure**		15,741
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		417
23	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**Counties Power Limited**
For Year Ended	**31 March 2020**

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

sch ref		Target ($000) [1]	Actual ($000)	% variance
7	**7(i): Revenue**			
8	Line charge revenue	51,742	51,702	(0%)
		Forecast ($000) [2]	**Actual ($000)**	**% variance**
9	**7(ii): Expenditure on Assets**			
10	Consumer connection	12,690	9,241	(27%)
11	System growth	26,420	26,698	1%
12	Asset replacement and renewal	13,360	12,537	(6%)
13	Asset relocations	300	48	(84%)
14	Reliability, safety and environment:			
15	Quality of supply	350	386	10%
16	Legislative and regulatory	–	1,722	–
17	Other reliability, safety and environment	1,195	–	(100%)
18	**Total reliability, safety and environment**	1,545	2,108	36%
19	**Expenditure on network assets**	54,315	50,632	(7%)
20	Expenditure on non-network assets	6,433	3,134	(51%)
21	Expenditure on assets	60,748	53,766	(11%)
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	1,900	2,038	7%
24	Vegetation management	1,350	1,512	12%
25	Routine and corrective maintenance and inspection	1,350	900	(33%)
26	Asset replacement and renewal	700	269	(62%)
27	**Network opex**	5,300	4,719	(11%)
28	System operations and network support	4,084	3,747	(8%)
29	Business support	6,179	7,275	18%
30	**Non-network opex**	10,263	11,022	7%
31	**Operational expenditure**	15,563	15,741	1%
32	**7(iv): Subcomponents of Expenditure on Assets (where known)**			
33	Energy efficiency and demand side management, reduction of energy losses	–	–	–
34	Overhead to underground conversion	300	5,862	1,854%
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	354	417	18%
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)*

1000

Company Name	Counties Power Limited
For Year Ended	31 March 2020
Network / Sub-Network Name	

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

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

sch ref	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)
15	Business	Commercial	Standard	6,883	116,428
16	3 Rate	Commercial	Standard	119	2,479
17	Standard Domestic	Residential	Standard	20,154	178,663
18	Low User Domestic	Residential	Standard	15,835	88,816
19	Prepaid Domestic	Residential	Standard	312	1,774
20	Time Of Use	Commercial	Standard	167	116,967
21	Streetlights	Commercial	Standard	6	1,579
22	Major Customer A	Commercial	Non-standard	3	51,837
23	Major Customer B	Commercial	Non-standard	2	7,746
24	Major Customer C	Commercial	Non-standard	2	36,336
25	Major Customer D	Commercial	Non-standard	2	14,975
26	*Add extra rows for additional consumer groups or price category codes as necessary*				
27			**Standard consumer totals**	43,476	506,706
28			**Non-standard consumer totals**	9	110,894
29			**Total for all consumers**	43,485	617,600

Billed quantities by price component

Price component	00700-1100	1700-2200	2400-0700	Anytime	Day	Econo	M/W Light	Night	Off Peak	Peak
Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh
Business	–	–	–	108,156	3	8,264	–	6	–	–
3 Rate	–	–	–	–	–	–	–	4	1,738	732
Standard Domestic	–	–	–	133,297	–	45,366	–	–	–	–
Low User Domestic	–	–	–	64,039	–	24,776	–	–	–	–
Prepaid Domestic	–	–	–	1,774	–	–	–	–	–	–
Time Of Use	24,785	37,860	26,668	–	–	–		–	27,654	–
Streetlights	–	–	–	–	–	–	42	–	–	–
Major Customer A	–	–	–	–	–	–	–	–	–	–
Major Customer B	–	–	–	–	–	–	–	–	–	–
Major Customer C	–	–	–	–	–	–	–	–	–	–
Major Customer D	–	–	–	–	–	–	–	–	–	–
Standard consumer totals	24,785	37,860	26,668	307,266	3	78,407	42	10	29,392	
Non-standard consumer totals	–	–	–	–	–	–	–	–	–	
Total for all consumers	24,785	37,860	26,668	307,266	3	78,407	42	10	29,392	

Price component	Priority Econo	Peak Saver	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	kWh	kWh	kVA	kVArh	Day	Day
Business	–	–	–	–	–	0	–	–	39	–	117	1,188	–
3 Rate	–	–	–	1	–	–	4	–	–	–	–	0	–
Standard Domestic	–	–	–	–	–	–	–	–	962	–	–	3,256	–
Low User Domestic	–	–	–	–	–	–	–	–	659	–	–	2,971	–
Prepaid Domestic	–	–	–	–	–	–	–	–	–	–	–	–	–
Time Of Use	–	–	–	–	–	–	–	–	–	388	6,045	–	6
Streetlights	–	–	–	–	1,537	–	–	–	–	–	–	0	–
Major Customer A	–	–	–	–	–	–	–	51,837	–	–	–	–	–
Major Customer B	–	–	–	–	–	–	–	7,746	–	–	–	–	–
Major Customer C	–	–	–	–	–	–	–	36,336	–	–	–	–	–
Major Customer D	–	–	–	–	–	–	–	14,975	–	–	–	–	–
Standard consumer totals	–	–	–	1	1,537	0	4	–	1,660	388	6,161	7,416	6
Non-standard consumer totals	–	–	–	–	–	–	–	110,894	–	–	–	–	–
Total for all consumers	–	–	–	1	1,537	0	4	110,894	1,660	388	6,161	7,416	6

32 **8(ii): Line Charge Revenues ($000) by Price Component**

sch ref	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	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)
38	Business	Commercial	Standard	$12,295	$1,998	$12,295	
39	3 Rate	Commercial	Standard	$228	$37	$228	
40	Standard Domestic	Residential	Standard	$18,879	$3,067	$18,879	
41	Low User Domestic	Residential	Standard	$9,252	$1,503	$9,252	
42	Prepaid Domestic	Residential	Standard	$166	$27	$166	
43	Time Of Use	Commercial	Standard	$7,808	$1,269	$7,808	
44	Streetlights	Commercial	Standard	$476	$77	$476	
45	Major Customer A	Industrial	Non-standard	$927	$151	$927	
46	Major Customer B	Industrial	Non-standard	$470	$76	$470	
47	Major Customer C	Industrial	Non-standard	$741	$120	$741	
48	Major Customer D	Industrial	Non-standard	$460	$75	$460	
49	*Add extra rows for additional consumer groups or price category codes as necessary*						
50			**Standard consumer totals**	$49,104	$7,978	$49,104	–
51			**Non-standard consumer totals**	$2,598	$422	$2,598	–
52			**Total for all consumers**	$51,702	$8,400	$51,702	–

Line charge revenues ($000) by price component

Price component	0700-1100	1700-2200	2400-0700	Anytime	Day	Econo	M/W Light	Night	Off Peak	Peak
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
Business	–	–	–	$9,803	–	$375	–	$1	–	–
3 Rate	–	–	–	–	–	–	–	–	$107	$121
Standard Domestic	–	–	–	$12,742	–	$1,979	–	–	–	–
Low User Domestic	–	–	–	$6,923	–	$1,579	–	–	–	–
Prepaid Domestic	–	–	–	$166	–	–	–	–	–	–
Time Of Use	$972	$1,458	$298	–	–	–	–	–	$435	–
Streetlights	–	–	–	–	–	–	$3	–	–	–
Major Customer A	–	–	–	–	–	–	–	–	–	–
Major Customer B	–	–	–	–	–	–	–	–	–	–
Major Customer C	–	–	–	–	–	–	–	–	–	–
Major Customer D	–	–	–	–	–	–	–	–	–	–
Standard consumer totals	$972	$1,458	$298	$29,634	–	$3,933	$3	$1	$542	$121
Non-standard consumer totals	–	–	–	–	–	–	–	–	–	
Total for all consumers	$972	$1,458	$298	$29,634	–	$3,933	$3	$1	$542	$121

Price component	Priority Econo	Peak Saver	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	$ per kWh	$ per kWh	$/kWh	$ per kVA	$ per kVArh	$ per Day	$ per Day
Business	–	–	–	–	–	–	–	–	–	–	$6	$2,110	–
3 Rate	–	–	–	–	–	–	–	–	–	–	–	–	–
Standard Domestic	–	–	–	–	–	–	–	–	$9	–	–	$4,150	–
Low User Domestic	–	–	–	–	–	–	–	–	$6	–	–	$743	–
Prepaid Domestic	–	–	–	–	–	–	–	–	–	–	–	–	–
Time Of Use	–	–	–	–	–	–	–	–	–	$3,551	$297	–	$797
Streetlights	–	–	–	–	–	$473	–	–	–	–	–	–	–
Major Customer A	–	–	–	–	–	–	–	$927	–	–	–	–	–
Major Customer B	–	–	–	–	–	–	–	$470	–	–	–	–	–
Major Customer C	–	–	–	–	–	–	–	$741	–	–	–	–	–
Major Customer D	–	–	–	–	–	–	–	$460	–	–	–	–	–
Standard consumer totals	–	–	–	–	–	$473	–	–	$15	$3,551	$303	$7,003	$797
Non-standard consumer totals	–	–	–	–	–	–	–	$2,598	–	–	–	–	–
Total for all consumers	–	–	–	–	–	$473	–	$2,598	$15	$3,551	$303	$7,003	$797

Check OK

54 **8(iii): Number of ICPs directly billed**

55 **Number of directly billed ICPs at year end** 9

Company Name	**Counties Power Limited**
For Year Ended	**31 March 2020**
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.	26,085	26,074	(11)	3
10	All	Overhead Line	Wood poles	No.	1,854	1,858	4	3
11	All	Overhead Line	Other pole types	No.	5	64	59	3
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	75	72	(3)	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	64	66	2	4
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	1	1	(0)	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	6	(1)	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	14	(3)	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	4
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	29	31	2	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	79	(1)	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	N/A
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	15	15	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1,458	1,456	(2)	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	207	202	(5)	3
39	HV	Distribution Cable	Distribution UG PILC	km	21	21	(0)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	2	2	(0)	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	174	40	(134)	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.	4,894	5,061	167	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.	222	278	56	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	3,151	3,177	26	3
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	871	917	46	3
48	HV	Distribution Transformer	Voltage regulators	No.	4	7	3	3
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	869	887	18	3
50	LV	LV Line	LV OH Conductor	km	729	723	(5)	3
51	LV	LV Cable	LV UG Cable	km	695	800	105	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	48	46	(2)	3
53	LV	Connections	OH/UG consumer service connections	No.	42,923	45,401	2,478	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	19	(10)	3
57	All	Load Control	Centralised plant	Lot	5	5	–	4
58	All	Load Control	Relays	No	3,469	3,469	–	3
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

Company Name **Counties Power Limited**
For Year Ended
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 2020

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	2020	No. with age unknown	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
9																																				
10	All	Overhead Line	Concrete poles / steel structure	No.	16	19	198	2,143	3,443	6,172	6,535	249	716	369	269	354	337	425	324	410	547	311	331	254	134	234	129	118	1,269	550	203	14	1	26,074	–	3
11	All	Overhead Line	Wood poles	No.	–	1	6	48	115	92	481	26	10	9	1	5	4	5	2	5	13	3	5	6	2	7	6	4	858	141	3	–	–	1,858	–	3
12	All	Overhead Line	Other pole types	No.	–	–	9	14	7	2	1	–	–	–	–	–	–	–	1	–	–	–	–	–	–	5	–	–	25	–	–	–	–	64	–	3
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	3	–	–	17	30	7	–	–	–	–	–	14	0	–	–	–	–	–	0	–	–	–	–	–	1	–	–	–	–	72	–	4
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	0	18	–	6	–	–	–	–	24	–	–	–	–	–	–	–	10	5	–	–	–	2	–	–	66	–	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	–	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.	–	–	2	4	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	6	–	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.	–	–	–	–	–	–	9	–	–	–	–	–	–	–	–	–	–	–	–	1	–	4	–	–	–	–	–	–	–	14	–	4
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	13	10	–	1	4	–	–	–	–	–	2	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	31	–	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.	–	–	8	4	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	12	–	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	6	8	–	–	11	–	–	–	–	–	–	–	8	–	–	–	–	29	–	17	–	–	–	–	–	–	–	79	–	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.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	12	–	3	–	–	–	–	–	–	–	15	–	4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	35	42	74	225	216	308	260	20	19	29	17	10	11	25	13	8	28	18	13	11	8	8	7	9	9	28	4	–	–	1,456	–	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	–	0	0	–	1	24	5	5	3	2	7	8	16	10	2	9	13	8	9	10	15	15	9	11	9	11	0	–	202	–	3
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	5	2	6	6	–	0	–	1	–	–	0	0	–	–	–	–	–	–	0	–	0	–	–	–	0	–	21	–	3
41	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	0	–	–	–	–	1	–	–	–	–	–	–	–	2	–	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	–	–	–	–	–	3	2	3	1	–	–	–	3	–	3	1	–	1	–	–	8	3	–	–	1	8	2	1	–	40	–	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	20	64	194	482	1,160	205	168	111	120	102	141	62	134	86	105	248	239	206	271	168	161	141	137	201	113	10	11	5,061	–	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	6	14	19	7	3	1	8	3	–	8	8	8	13	11	8	14	7	18	12	13	27	23	36	5	–	278	–	3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	–	18	28	105	264	567	63	98	67	89	84	91	46	92	39	52	179	202	171	238	137	140	106	80	132	76	10	3	3,177	–	3
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	–	4	10	32	142	27	19	19	25	21	28	28	26	31	19	40	47	30	64	49	43	42	60	62	39	8	2	917	–	3
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	–	1	2	–	–	1	1	–	–	–	–	–	–	7	–	3
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	2	2	18	134	27	19	19	25	21	28	28	26	31	19	39	47	41	64	52	43	39	59	56	38	8	2	887	–	3
51	LV	LV Line	LV OH Conductor	km	–	–	1	2	4	4	660	7	4	6	3	2	3	2	1	3	4	1	4	2	2	2	1	1	1	2	2	–	0	723	–	3
52	LV	LV Cable	LV UG Cable	km	–	–	0	1	8	4	226	23	20	21	16	16	35	42	22	15	8	21	14	30	24	44	34	39	42	47	32	5	11	800	–	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	2	9	6	6	6	6	0	1	1	–	0	46	–	3
54	LV	Connections	OH/UG consumer service connections	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	3
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	3
56	All	SCADA and communications	SCADA and communications equipment operating as a single syst	Lot	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	1	–	4
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	19	19	–	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 2020**
Network / Sub-network Name	

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref				
9				
10	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**
11	> 66kV	66	–	66
12	50kV & 66kV	–	–	–
13	33kV	72	1	73
14	SWER (all SWER voltages)	–	–	–
15	22kV (other than SWER)	569	170	739
16	6.6kV to 11kV (inclusive—other than SWER)	888	80	968
17	Low voltage (< 1kV)	723	800	1,523
18	**Total circuit length (for supply)**	2,318	1,051	3,369
19				
20	Dedicated street lighting circuit length (km)	0	48	48
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			2
22				
23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**	
24	Urban	196	8%	
25	Rural	2,057	89%	
26	Remote only	–	–	
27	Rugged only	65	3%	
28	Remote and rugged	–	–	
29	Unallocated overhead lines	–	–	
30	**Total overhead length**	2,318	100%	
31				
32		**Circuit length (km)**	**(% of total circuit length)**	
33	Length of circuit within 10km of coastline or geothermal areas (where known)	1,515	45%	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	2,318	100%	

Company Name	**Counties Power Limited**
For Year Ended	**31 March 2020**

SCHEDULE 9d: REPORT ON EMBEDDED NETWORKS

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

sch ref	Location *	Number of ICPs served	Line charge revenue ($000)
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 2020**
Network / Sub-network Name	

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref

sch ref				
8	**9e(i): Consumer Connections**			
9	*Number of ICPs connected in year by consumer type*			
10	*Consumer types defined by EDB**	**Number of connections (ICPs)**		
11	Urban Residential	516		
12	Urban Commercial	370		
13	Rural Residential	287		
14	Rural Commercial	275		
15				
16	** include additional rows if needed*			
17	**Connections total**	1,448		
18				
19	**Distributed generation**			
20	Number of connections made in year	119	**connections**	
21	Capacity of distributed generation installed in year	3.27	**MVA**	
22	**9e(ii): System Demand**			
23				
24		**Demand at time of maximum coincident demand (MW)**		
25	**Maximum coincident system demand**			
26	GXP demand	122		
27	*plus* Distributed generation output at HV and above	7		
28	**Maximum coincident system demand**	129		
29	*less* Net transfers to (from) other EDBs at HV and above			
30	**Demand on system for supply to consumers' connection points**	129		
31	**Electricity volumes carried**	**Energy (GWh)**		
32	Electricity supplied from GXPs	612		
33	*less* Electricity exports to GXPs	–		
34	*plus* Electricity supplied from distributed generation	37		
35	*less* Net electricity supplied to (from) other EDBs			
36	**Electricity entering system for supply to consumers' connection points**	649		
37	*less* Total energy delivered to ICPs	618		
38	**Electricity losses (loss ratio)**	31		4.8%
39				
40	**Load factor**	0.57		
41	**9e(iii): Transformer Capacity**			
42		**(MVA)**		
43	Distribution transformer capacity (EDB owned)	431		
44	Distribution transformer capacity (Non-EDB owned, estimated)	56		
45	**Total distribution transformer capacity**	487		
46				
47	**Zone substation transformer capacity**	483		

Company Name	**Counties Power Limited**
For Year Ended	**31 March 2020**
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**		
9	**Interruptions by class**	**Number of interruptions**	
10	Class A (planned interruptions by Transpower)	1	
11	Class B (planned interruptions on the network)	319	
12	Class C (unplanned interruptions on the network)	317	
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)	1	
18	Class I (interruptions caused by parties not included above)	30	
19	**Total**	668	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	195	122
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)	0.00	0.6
26	Class B (planned interruptions on the network)	0.58	170.6
27	Class C (unplanned interruptions on the network)	2.54	159.1
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)	0.00	0.0
33	Class I (interruptions caused by parties not included above)	0.01	3.0
34	**Total**	3.14	333.3
35			
36	**Normalised SAIFI and SAIDI**	**Normalised SAIFI**	**Normalised SAIDI**
37	Classes B & C (interruptions on the network)	3.12	326.2
38			
39	**10(ii): Class C Interruptions and Duration by Cause**		
40			
41	**Cause**	**SAIFI**	**SAIDI**
42	Lightning	0.04	2.5
43	Vegetation	0.36	20.5
44	Adverse weather		
45	Adverse environment		
46	Third party interference	0.25	25.6
47	Wildlife	0.22	6.4
48	Human error		
49	Defective equipment	1.02	80.4
50	Cause unknown	0.65	23.7
51			
52	**10(iii): Class B Interruptions and Duration by Main Equipment Involved**		
53			
54	**Main equipment involved**	**SAIFI**	**SAIDI**
55	Subtransmission lines	0.00	0.3
56	Subtransmission cables		
57	Subtransmission other	0.00	0.7
58	Distribution lines (excluding LV)	0.50	145.2
69	Distribution cables (excluding LV)	0.07	23.8
60	Distribution other (excluding LV)	0.00	0.6

Company Name	**Counties Power Limited**
For Year Ended	**31 March 2020**
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

	Main equipment involved	SAIFI	SAIDI
64	Subtransmission lines	0.10	1.0
65	Subtransmission cables	0.00	0.0
66	Subtransmission other	0.23	15.9
67	Distribution lines (excluding LV)	2.04	132.9
68	Distribution cables (excluding LV)	0.16	8.6
69	Distribution other (excluding LV)	0.01	0.7

70 ### 10(v): Fault Rate

71	Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
72	Subtransmission lines	3	138	2.17
73	Subtransmission cables	1	1	90.91
74	Subtransmission other	2		
75	Distribution lines (excluding LV)	300	1,457	20.59
76	Distribution cables (excluding LV)	8	250	3.20
77	Distribution other (excluding LV)	3		
78	**Total**	317		

Company Name	Counties Power Limited
For Year Ended	31 March 2020

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 6.4% in FY19 to 5.8% in FY20 with the following items of note:

- Gross Line Revenue (before posted discount) increased by 3.4% in FY20. Higher posted discounts of $8.4m (FY19 - $6.0m) reduced net revenue to $51.7m (FY19 -$52.1m);
- Operational costs increased from 28% of lines revenue in FY19 to 30% of lines revenue this year to address high network growth and targeted improvements in reliability and the customer experience; and
- Revaluations increased from $3.8m in FY19 to $6.8m in FY20. This was mainly attributable to higher CPI of 2.5% (FY19 – 1.1%).

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
There were no mergers or acquisitions during the disclosure year.

Value of the Regulatory Asset Base (Schedule 4)

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

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

There were no changes to RAB classifications from the prior year.

Assets being disposed of comprise non-system minor plant and equipment ($6k) and transformers sold as scrap ($36k). A loss of $40k was recorded for these disposals.

In line with the final decision paper on the treatment of operating leases published by the Commerce Commission on 13 November 2019, right-of-use assets have been included in the RAB. As the current year was the first year of adoption of NZ IFRS 16, we have included the right-of-use assets in the "Assets commissioned" line of "Distribution and LV lines". This has increased the RAB by $1,722,000.

Depreciation has increased for non-network assets due to higher IT commissioned assets in the previous year.

The high WIP balance is due largely to the construction of the new Pokeno substation that was not commissioned at 31 March 2020.

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 ($42k) and entertainment expense ($14k).

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 ($84k @28% = $24k).

Holiday leave provision - $356k (FY19 - $314k)

Other leave provisions - $107k (FY19 - $105k)

Doubtful debt provision - $171k (FY19 - $335k)

Other provisions - $36k (FY19 – nil)

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.

No 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

Operational expenditure includes items such as cable and conductor repairs, insulator replacements, transformer and switch repairs, and other work of a non-capital nature.

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): Line charge revenue was in line with target.

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

•Consumer connections were 27% below target due to lower commercial connections.

•Asset relocations were lower than target with some anticipated third party asset relocation projects not progressing and design alterations meaning relocation work was not needed in the final network configurations.

•Legislative and regulatory is the Right of use assets (IFRS16 adjustment).

•Other reliability target was not achieved as specific reliability only projects were encompassed within system growth and asset renewal projects.

•Expenditure on non-network assets was lower than forecast due to a delayed start for the Glasgow site upgrade.

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

• The routine and corrective maintenance programme was completed but fell below target (33%) with higher levels of upgrades carried out that were capital in nature;

•Vegetation management was 12% above target with additional work carried out to improve network reliability; and

• Operational Asset replacement was 62% below target - this was due to higher capitalisation while carrying out asset replacement work.

•Higher business support reflects continued investment in the areas of Network support, IT and customer relationship management.

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

•A number of projects were converted from overhead to underground where there were benefits, including reliability and safety, that outweighed the additional cost.

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 in line with the target of $51.7m.

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

Both planned (class B) and unplanned (class C) outages, as measured by SAIDI, returned a satisfactory result for FY20. Normalised planned and unplanned SAIDI was 15% less than the yearly average over the prior two-year period (FY18-FY19 average).

Planned SAIDI was 13% less than the yearly average over the prior two-year period (FY18-FY19 average). This reduction was largely due to the location of one major overhead rehabilitation project, where works could be completed with a minimal number of customers effected during each outage.

Unplanned SAIDI was 48% less than the yearly average over the prior two-year period (FY18-FY19 average). All fault causes saw a drop in SAIDI attributed to each, with vegetation having the largest reduction of 84%.

Similar to SAIDI, both planned and unplanned outages, as measured by SAIFI, returned a satisfactory result for FY20. Normalised planned and unplanned SAIFI was 22% less than the yearly average over the prior two-year period (FY18-FY19 average). Planned SAIFI was 19% less and unplanned SAIFI saw a reduction by 23%.

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.

For consistency with our thresholds and prior years we have reported the information in Schedule 10 in line with our interpretation as outlined above, thus Counties Power have accepted the "Successive Interruption" exemption. However, we have also recalculated SAIFI based on the alternative interpretation and note SAIFI for FY20 would increase by 7.96% from 3.14 to 3.39 and normalised planned and unplanned SAIFI by 8.01% from 3.12 to 3.37.

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 10 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 2% 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 2% 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
There are no voluntary disclosures this year.

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[1] 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 2020

HW Stevens
26 August 2020

(1) The Directors of Counties Power Limited note the amendment to the ID Determination issued by the Commerce Commission on 9 April 2020 that has removed the auditor report requirements relating to the treatment of successive interruptions for reporting SAIDI, SAIFI and interruptions, because of potential inconsistencies in treatments approaches across the industry. The Directors note that they do not appear to have been provided a similar exemption relating to the treatment of successive interruptions regarding their certification. Counties Power Limited has continued to report the treatment of successive interruptions consistent with previous periods, including periods used to establish quality standards by which subsequent performance is measured.

Independent Assurance Report

To the Directors of Counties Power Limited and the Commerce Commission

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

- whether the information required to be disclosed in accordance with the Electricity Distribution Information Disclosure Determination 2012 as amended by the Information Disclosure exemption: Disclosure and auditing of reliability information within schedule 10, issued by the Commerce Commission on 9 April 2020 (the 'Determination, as amended') for the disclosure year ended 31 March 2020, have been prepared, in all material respects, in accordance with the Determination, as amended.

  The disclosure information required to be reported by the Company, and audited by the Auditor-General under the Determination, as amended, is in schedules 1 to 4, 5a to 5g, 6a and 6b, 7, 10, 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 2020, has been prepared, in all material respects, in accordance with clause 2.3.6 of the Determination, as amended, 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 Determination, as amended; and
- the Related Party Transaction Information complies, in all material respects, with the Determination, as amended 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 of opinion

We conducted our engagement in accordance with the International Standard on Assurance Engagements (New Zealand) 3000 (Revised) *Assurance Engagements Other Than Audits or Reviews of Historical Financial Information* and the Standard on Assurance Engagements 3100 (Revised): *Assurance Engagements on Compliance* 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 Determination, as amended and about whether the Related Party Transaction Information has been prepared, in all material respects, with the Determination, as amended 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 or error or non-compliance with the Determination, as amended 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 fixed assets in the financial statements, however, there are a number of different requirements and complexities which require careful consideration.	We have obtained an understanding of the compliance requirements relevant to the RAB as set out in the Information Disclosure Determination, as amended (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;

Key assurance matter	How our procedures addressed the key assurance matter
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 assurance matter.	*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 verified the spreadsheet formula utilised to calculate regulatory depreciation expense is 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.
Cost and asset allocation The ID Determination, as amended 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. 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.	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;

Key assurance matter	How our procedures addressed the key assurance matter
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.	• testing a sample of assets commissioned to invoice to ensure their classification as either directly attributable or not directly attributable are appropriate and in line with the ID determination; *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 the ABAA to not directly attributable costs including surveying a sample of staff to understand their role and allocation of time; and • 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 Determination, as amended; and
- the Related Party Transaction Information in accordance with the Determination, as amended 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 is free from material misstatement.

Our responsibility for the Disclosure Information and the Related Party Information

Our responsibility is to express an opinion on whether:

- the Disclosure Information has been prepared, in all material respects, in accordance with the Determination, as amended; and
- the Related Party Transaction Information has been prepared, in all material respects, in accordance with the Determination, as amended 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 Determination, as amended; 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. Other than any dealings on normal terms within the ordinary course of business, this engagement, and the annual audit of the Company's financial statements, we have no relationship with or interests in the Company.

Use of this report

This independent assurance report has been prepared solely for the directors of the Company and for the Commerce Commission for the purpose of providing those parties with reasonable assurance about whether the Disclosure Information has been prepared, in all material respects, in accordance with the Determination, as amended and whether the Related Party Transaction Information has been prepared, in all material respects, in accordance with the Determination, as amended 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

Mark Bramley
PricewaterhouseCoopers

On behalf of the Auditor-General
Auckland, New Zealand
26 August 2020