Counties Energy

Information Disclosure prepared in accordance with the

Electricity Distribution Information Disclosure Determination 2012

For the Year Ended 31 March 2023

Contents

1. Current Year Schedules

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2023**

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 this ID determination. This will include information disclosed in accordance with this and other schedules, and information disclosed under the other requirements of this determination.

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

sch ref

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

sch ref		Expenditure per GWh energy delivered to ICPs ($/GWh)	Expenditure per average no. of ICPs ($/ICP)	Expenditure per MW maximum coincident system demand ($/MW)	Expenditure per km circuit length ($/km)	Expenditure per MVA of capacity from EDB-owned distribution transformers ($/MVA)
8						
9	**Operational expenditure**	37,606	521	182,627	6,903	56,128
10	Network	13,283	184	64,507	2,438	19,826
11	Non-network	24,323	337	118,119	4,464	36,303
12						
13	**Expenditure on assets**	94,926	1,315	460,993	17,424	141,681
14	Network	82,355	1,141	399,940	15,116	122,917
15	Non-network	12,572	174	61,052	2,308	18,764
16						

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

sch ref		Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
18			
19	**Total consumer line charge revenue**	94,948	1,316
20	Standard consumer line charge revenue	105,179	1,237
21	Non-standard consumer line charge revenue	37,654	412,523
22			

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

sch ref			
24			
25	Demand density	38	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
26	Volume density	184	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
27	Connection point density	13	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
28	Energy intensity	13,857	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*
29			

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

sch ref		($000)	% of revenue
31			
32	Operational expenditure	24,472	39.84%
33	Pass-through and recoverable costs excluding financial incentives and wash-ups	12,823	20.88%
34	Total depreciation	13,441	21.88%
35	Total revaluations	24,806	40.38%
36	Regulatory tax allowance	2,548	4.15%
37	Regulatory profit/(loss) including financial incentives and wash-ups	32,946	53.64%
38	**Total regulatory income**	61,425	
39			

40 **1(v): Reliability**

sch ref			
41			
42	Interruption rate	29.64	*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 this 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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

sch ref		CY-2	CY-1	Current Year CY
7	**2(i): Return on Investment**			
9	**ROI – comparable to a post tax WACC**	%	%	%
10	Reflecting all revenue earned	3.69%	9.62%	8.46%
11	Excluding revenue earned from financial incentives	3.69%	9.62%	8.46%
12	Excluding revenue earned from financial incentives and wash-ups	3.69%	9.62%	8.46%
14	**Mid-point estimate of post tax WACC**	3.72%	3.52%	4.88%
15	25th percentile estimate	3.04%	2.84%	4.20%
16	75th percentile estimate	4.40%	4.20%	5.56%
19	**ROI – comparable to a vanilla WACC**			
20	Reflecting all revenue earned	4.02%	9.92%	8.98%
21	Excluding revenue earned from financial incentives	4.02%	9.92%	8.98%
22	Excluding revenue earned from financial incentives and wash-ups	4.02%	9.92%	8.98%
24	**WACC rate used to set regulatory price path**			
26	**Mid-point estimate of vanilla WACC**	4.05%	3.82%	5.39%
27	25th percentile estimate	3.37%	3.14%	4.71%
28	75th percentile estimate	4.73%	4.50%	6.07%

sch ref				($000)	
30	**2(ii): Information Supporting the ROI**				
32		Total opening RAB value	374,478		
33	*plus*	Opening deferred tax	(21,603)		
34	**Opening RIV**			352,875	
36	**Line charge revenue**			61,787	
38		Expenses cash outflow	37,295		
39	*add*	Assets commissioned	41,748		
40	*less*	Asset disposals	537		
41	*add*	Tax payments	29		
42	*less*	Other regulated income	(362)		
43	**Mid-year net cash outflows**			78,897	
45	**Term credit spread differential allowance**			–	
47		Total closing RAB value	427,054		
48	*less*	Adjustment resulting from asset allocation	(0)		
49	*less*	Lost and found assets adjustment	–		
50	*plus*	Closing deferred tax	(24,123)		
51	**Closing RIV**			402,932	
53	**ROI – comparable to a vanilla WACC**				8.98%
55		Leverage (%)			42%
56		Cost of debt assumption (%)			4.38%
57		Corporate tax rate (%)			28%
59	**ROI – comparable to a post tax WACC**				8.46%

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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**	8.82%
96	**Year-end ROI – comparable to a post tax WACC**	8.30%

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

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

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

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SCHEDULE 3: REPORT ON REGULATORY PROFIT

This schedule requires information on the calculation of regulatory profit for the EDB for the disclosure year. All EDBs must complete all sections and provide explanatory comment on their regulatory profit in Schedule 14 (Mandatory Explanatory Notes).
This information is part of audited disclosure information (as defined in section 1.4 of this 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		61,787
10	*plus*	Gains / (losses) on asset disposals		(448)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)		86
12				
13		**Total regulatory income**		61,425
14		**Expenses**		
15	*less*	Operational expenditure		24,472
16				
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups		12,823
18				
19		**Operating surplus / (deficit)**		24,130
20				
21	*less*	Total depreciation		13,441
22				
23	*plus*	Total revaluations		24,806
24				
25		**Regulatory profit / (loss) before tax**		35,494
26				
27	*less*	Term credit spread differential allowance		–
28				
29	*less*	Regulatory tax allowance		2,548
30				
31		**Regulatory profit/(loss) including financial incentives and wash-ups**		32,946
32				
33		**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	**($000)**	
34		**Pass through costs**		
35		Rates	782	
36		Commerce Act levies	114	
37		Industry levies	126	
38		CPP specified pass through costs		
39		**Recoverable costs excluding financial incentives and wash-ups**		
40		Electricity lines service charge payable to Transpower	11,250	
41		Transpower new investment contract charges		
42		System operator services		
43		Distributed generation allowance	551	
44		Extended reserves allowance		
45		Other recoverable costs excluding financial incentives and wash-ups		
46		**Pass-through and recoverable costs excluding financial incentives and wash-ups**		12,823
47				

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SCHEDULE 3: REPORT ON REGULATORY PROFIT

This schedule requires information on the calculation of regulatory profit for the EDB for the disclosure year. All EDBs must complete all sections and provide explanatory comment on their regulatory profit in Schedule 14 (Mandatory Explanatory Notes).
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sch ref			
48	**3(iii): Incremental Rolling Incentive Scheme**	**($000)**	
49		**CY-1**	**CY**
50			**31 Mar 23**
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 [year]		
58	CY-4 [year]		
59	CY-3 [year]		
60	CY-2 [year]		
61	CY-1 [year]		
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 this 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 CY-4 ($000)	RAB CY-3 ($000)	RAB CY-2 ($000)	RAB CY-1 ($000)	RAB CY ($000)
Total opening RAB value	253,205	270,478	287,274	330,036	374,478
less **Total depreciation**	8,228	9,353	10,565	12,097	13,441
plus **Total revaluations**	3,754	6,847	4,364	22,796	24,806
plus **Assets commissioned**	22,431	19,344	49,142	33,968	41,748
less **Asset disposals**	92	42	179	225	537
plus **Lost and found assets adjustment**				–	–
plus **Adjustment resulting from asset allocation**	(592)			–	(0)
Total closing RAB value	270,478	287,274	330,036	374,478	427,054

4(ii): Unallocated Regulatory Asset Base

	Unallocated RAB * ($000)	Unallocated RAB * ($000)	RAB ($000)	RAB ($000)
Total opening RAB value		375,871		374,478
less				
Total depreciation		13,541		13,441
plus				
Total revaluations		24,898		24,806
plus				
Assets commissioned (other than below)	42,120		41,748	
Assets acquired from a regulated supplier				
Assets acquired from a related party				
Assets commissioned		42,120		41,748
less				
Asset disposals (other than below)	571		537	
Asset disposals to a regulated supplier				
Asset disposals to a related party				
Asset disposals		571		537
plus **Lost and found assets adjustment**				
plus **Adjustment resulting from asset allocation**				(0)
Total closing RAB value		428,778		427,054

** 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	1,218
CPI_4^{-4}	1,142
Revaluation rate (%)	6.65%

	Unallocated RAB * ($000)	Unallocated RAB * ($000)	RAB ($000)	RAB ($000)
Total opening RAB value	375,871		374,478	
less Opening value of fully depreciated, disposed and lost assets	1,739		1,739	
Total opening RAB value subject to revaluation	374,132		372,739	
Total revaluations		24,898		24,806

4(iv): Roll Forward of Works Under Construction

	Unallocated works under construction		Allocated works under construction	
Works under construction—preceding disclosure year		21,175		21,175
plus Capital expenditure	39,444		39,072	
less Assets commissioned	42,120		41,748	
plus Adjustment resulting from asset allocation				
Works under construction - current disclosure year		18,499		18,499
Highest rate of capitalised finance applied				5.59%

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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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

75

76 ### 4(v): Regulatory Depreciation

sch ref		Unallocated RAB *		RAB	
78		($000)	($000)	($000)	($000)
79	Depreciation - standard	10,691		10,691	
80	Depreciation - no standard life assets	2,850		2,750	
81	Depreciation - modified life assets				
82	Depreciation - alternative depreciation in accordance with CPP				
83	**Total depreciation**		13,541		13,441

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**	18,209	220	60,612	131,284	51,335	45,902	24,209	6,228	36,479	374,478
100	*less*	Total depreciation	433	10	1,598	3,473	1,722	1,783	985	617	2,820	13,441
101	*plus*	Total revaluations	1,212	15	4,018	8,737	3,413	3,044	1,608	414	2,345	24,806
102	*plus*	Assets commissioned	531	–	11,804	14,504	2,765	785	1,225	1,952	8,182	41,748
103	*less*	Asset disposals	–	–	–	–	–	156	–	–	381	537
104	*plus*	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
105	*plus*	Adjustment resulting from asset allocation	–	–	–	–	–	–	–	–	–	–
106	*plus*	Asset category transfers	–	–	–	–	–	–	–	–	–	–
107		**Total closing RAB value**	19,519	225	74,836	151,052	55,791	47,792	26,057	7,977	43,805	427,054
108												
109		**Asset Life**										
110		Weighted average remaining asset life	42.8	23.3	38.5	44.5	36.1	31	29.1	8	13	(years)
111		Weighted average expected total asset life	60	45	45	60	60	45	35	15	16.7	(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 this ID determination), and so is subject to the assurance report required by section 2.8

sch ref					
7	**5a(i): Regulatory Tax Allowance**				**($000)**
8		**Regulatory profit / (loss) before tax**			35,494
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	154	*	
12		Amortisation of initial differences in asset values	2,663		
13		Amortisation of revaluations	1,949		
14					4,766
15					
16	*less*	Total revaluations	24,806		
17		Income included in regulatory profit / (loss) before tax but not taxable		*	
18		Discretionary discounts and customer rebates			
19		Expenditure or loss deductible but not in regulatory profit / (loss) before tax		*	
20		Notional deductible interest	6,354		
21					31,160
22					
23		**Regulatory taxable income**			9,101
24					
25	*less*	Utilised tax losses			
26		Regulatory net taxable income			9,101
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**			2,548
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	63,912		
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			
40		Closing unamortised initial differences in asset values			61,249
41					
42		Opening weighted average remaining useful life of relevant assets (years)			24
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 this ID determination), and so is subject to the assurance report required by section 2.8

sch ref				
44	**5a(iv): Amortisation of Revaluations**			**($000)**
46		Opening sum of RAB values without revaluations	319,602	
48		Adjusted depreciation	11,492	
49		Total depreciation	13,441	
50		Amortisation of revaluations		1,949
52	**5a(v): Reconciliation of Tax Losses**			**($000)**
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)**
60		**Opening deferred tax**	(21,603)	
62	*plus*	Tax effect of adjusted depreciation	3,218	
64	*less*	Tax effect of tax depreciation	4,984	
66	*plus*	Tax effect of other temporary differences*	(8)	
68	*less*	Tax effect of amortisation of initial differences in asset values	746	
70	*plus*	Deferred tax balance relating to assets acquired in the disclosure year		
72	*less*	Deferred tax balance relating to assets disposed in the disclosure year	–	
74	*plus*	Deferred tax cost allocation adjustment	0	
76		**Closing deferred tax**		(24,123)
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).*		
81	**5a(viii): Regulatory Tax Asset Base Roll-Forward**			
82				**($000)**
83		**Opening sum of regulatory tax asset values**	177,243	
84	*less*	Tax depreciation	17,799	
85	*plus*	Regulatory tax asset value of assets commissioned	41,748	
86	*less*	Regulatory tax asset value of asset disposals	537	
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**		200,655

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

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

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

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

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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 this 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 Energy 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 Energy Limited**
For Year Ended	**31 March 2023**

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 this 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		2,801			
Not directly attributable				–	
Total attributable to regulated service		2,801			
Vegetation management					
Directly attributable		2,422			
Not directly attributable				–	
Total attributable to regulated service		2,422			
Routine and corrective maintenance and inspection					
Directly attributable		2,525			
Not directly attributable				–	
Total attributable to regulated service		2,525			
Asset replacement and renewal					
Directly attributable		896			
Not directly attributable				–	
Total attributable to regulated service		896			
System operations and network support					
Directly attributable		4,106			
Not directly attributable				–	
Total attributable to regulated service		4,106			
Business support					
Directly attributable		598			
Not directly attributable		11,124	1,368	12,492	
Total attributable to regulated service		11,722			
Operating costs directly attributable		13,348			
Operating costs not directly attributable	–	11,124	1,368	12,492	–
Operational expenditure		24,472			

5d(ii): Other Cost Allocations

Pass through and recoverable costs	**($000)**
Pass through costs	
Directly attributable	920
Not directly attributable	
Total attributable to regulated service	920
Recoverable costs	
Directly attributable	11,801
Not directly attributable	
Total attributable to regulated service	11,801

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

Change in cost allocation 1

Cost category	
Original allocator or line items	
New allocator or line items	

($000)	CY-1	Current Year (CY)
Original allocation		
New allocation		
Difference	–	–

Rationale for change

Change in cost allocation 2

Cost category	
Original allocator or line items	
New allocator or line items	

($000)	CY-1	Current Year (CY)
Original allocation		
New allocation		
Difference	–	–

Rationale for change

Change in cost allocation 3

Cost category	
Original allocator or line items	
New allocator or line items	

($000)	CY-1	Current Year (CY)
Original allocation		
New allocation		
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 Energy Limited**
For Year Ended	**31 March 2023**

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 this 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	19,519
Not directly attributable	–
Total attributable to regulated service	19,519
Subtransmission cables	
Directly attributable	225
Not directly attributable	–
Total attributable to regulated service	225
Zone substations	
Directly attributable	74,836
Not directly attributable	–
Total attributable to regulated service	74,836
Distribution and LV lines	
Directly attributable	151,052
Not directly attributable	–
Total attributable to regulated service	151,052
Distribution and LV cables	
Directly attributable	55,791
Not directly attributable	–
Total attributable to regulated service	55,791
Distribution substations and transformers	
Directly attributable	47,792
Not directly attributable	–
Total attributable to regulated service	47,792
Distribution switchgear	
Directly attributable	26,057
Not directly attributable	–
Total attributable to regulated service	26,057
Other network assets	
Directly attributable	7,977
Not directly attributable	–
Total attributable to regulated service	7,977
Non-network assets	
Directly attributable	31,949
Not directly attributable	11,856
Total attributable to regulated service	43,805
Regulated service asset value directly attributable	415,198
Regulated service asset value not directly attributable	11,856
Total closing RAB value	427,054

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

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

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

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

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

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2023**

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 this 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		23,064
9		System growth		912
10		Asset replacement and renewal		28,964
11		Asset relocations		169
12		Reliability, safety and environment:		
13		Quality of supply	483	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	–	
16		**Total reliability, safety and environment**		483
17		**Expenditure on network assets**		53,592
18		Expenditure on non-network assets		8,181
19				
20		**Expenditure on assets**		61,773
21	*plus*	Cost of financing		397
22	*less*	Value of capital contributions		23,098
23	*plus*	Value of vested assets		–
24				
25		**Capital expenditure**		39,072

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	601
29	Research and development	–
	Cybersecurity (Commission only)	–

30		**6a(iii): Consumer Connection**		
31		*Consumer types defined by EDB**	**($000)**	**($000)**
32		Urban Residential	8,925	
33		Urban Commercial	7,891	
34		Rural Residential	4,463	
35		Rural Commercial	1,785	
36				
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		23,064
39				
40	*less*	Capital contributions funding consumer connection expenditure	16,288	
41		**Consumer connection less capital contributions**		6,776

42		**6a(iv): System Growth and Asset Replacement and Renewal**		**Asset Replacement and**
43			**System Growth**	**Renewal**
44			**($000)**	**($000)**
45		Subtransmission	–	159
46		Zone substations	591	2,472
47		Distribution and LV lines	304	15,364
48		Distribution and LV cables	17	7,222
49		Distribution substations and transformers	–	571
50		Distribution switchgear	–	1,224
51		Other network assets	–	1,952
52		**System growth and asset replacement and renewal expenditure**	912	28,964
53	*less*	Capital contributions funding system growth and asset replacement and renewal	–	6,810
54		**System growth and asset replacement and renewal less capital contributions**	912	22,154
55				

56		**6a(v): Asset Relocations**		
57		*Project or programme**	**($000)**	**($000)**
58		Various relocation (largely reimbursed by customers)	169	
59				
60				
61				
62				
63		** include additional rows if needed*		
64		All other projects or programmes - asset relocations		
65		**Asset relocations expenditure**		169
66	*less*	Capital contributions funding asset relocations		
67		**Asset relocations less capital contributions**		169

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2023**

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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref			($000)	($000)
68				
69		**6a(vi): Quality of Supply**		
70		*Project or programme**	**($000)**	**($000)**
71		Voltage upgrades	483	
72				
73				
74				
75				
76		** include additional rows if needed*		
77		All other projects programmes - quality of supply		
78		**Quality of supply expenditure**		483
79	*less*	Capital contributions funding quality of supply		
80		**Quality of supply less capital contributions**		483
81		**6a(vii): Legislative and Regulatory**		
82		*Project or programme**	**($000)**	**($000)**
83		Nil		
84				
85				
86				
87				
88		** include additional rows if needed*		
89		All other projects or programmes - legislative and regulatory		
90		**Legislative and regulatory expenditure**		–
91	*less*	Capital contributions funding legislative and regulatory		
92		**Legislative and regulatory less capital contributions**		–
93		**6a(viii): Other Reliability, Safety and Environment**		
94		*Project or programme**	**($000)**	**($000)**
95		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 equipment and software	3,310	
110		Land & buildings	3,154	
111		Vehicles	341	
112		Other plant and equipment	1,376	
113				
114		** include additional rows if needed*		
115		All other projects or programmes - routine expenditure		
116		**Routine expenditure**		8,181
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**		8,181

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2023**

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 this 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	2,801	
9	Vegetation management	2,422	
10	Routine and corrective maintenance and inspection	2,525	
11	Asset replacement and renewal	896	
12	**Network opex**		8,644
13	System operations and network support	4,106	
14	Business support	11,722	
15	**Non-network opex**		15,828
16			
17	**Operational expenditure**		24,472
18	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
19	*EDBs' must disclose both a public version of this Schedule (excluding cybersecurity cost data) and a confidential version of this Schedule (including cybersecurity costs)*		
20	Energy efficiency and demand side management, reduction of energy losses		
21	Direct billing*		
22	Research and development		
23	Insurance		583
24	Cybersecurity (Commission only)		
25	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2023**

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 this ID determination), and so is subject to the assurance report required by section 2.8. For the purpose of this audit, target revenue and forecast expenditures only need to be verified back to previous disclosures.

sch ref				
7	**7(i): Revenue**	**Target ($000) [1]**	**Actual ($000)**	**% variance**
8	Line charge revenue	62,717	61,787	(1%)
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	14,000	23,064	65%
11	System growth	12,287	912	(93%)
12	Asset replacement and renewal	32,447	28,964	(11%)
13	Asset relocations	300	169	(44%)
14	Reliability, safety and environment:			
15	Quality of supply	1,772	483	(73%)
16	Legislative and regulatory	–	–	–
17	Other reliability, safety and environment	70	–	(100%)
18	**Total reliability, safety and environment**	1,842	483	(74%)
19	**Expenditure on network assets**	60,876	53,592	(12%)
20	Expenditure on non-network assets	15,022	8,181	(46%)
21	Expenditure on assets	75,898	61,773	(19%)
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	2,800	2,801	0%
24	Vegetation management	2,090	2,422	16%
25	Routine and corrective maintenance and inspection	2,097	2,525	20%
26	Asset replacement and renewal	1,628	896	(45%)
27	**Network opex**	8,615	8,644	0%
28	System operations and network support	3,868	4,106	6%
29	Business support	10,684	11,722	10%
30	**Non-network opex**	14,552	15,828	9%
31	**Operational expenditure**	23,167	24,472	6%
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	–	601	–
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	567	583	3%
42				
43	*1 From the nominal dollar target revenue for the disclosure year disclosed under clause 2.4.3(3) of this determination*			
44	*2 From the CY+1 nominal dollar expenditure forecasts disclosed in accordance with clause 2.6.6 for the forecast period starting at the beginning of the disclosure year (the second to last disclosure of Schedules 11a and 11b)*			

Company Name	Counties Energy Limited
For Year Ended	31 March 2023
vork / Sub-Network Name	

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

8(i): Billed Quantities by Price Component

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	6,994	115,325
16	3 Rate	Commercial	Standard	12	3,905
17	Standard Domestic	Residential	Standard	21,557	207,614
18	Low User Domestic	Residential	Standard	18,210	101,255
19	Prepaid Domestic	Residential	Standard		–
	Time Of Use	Commercial	Standard	172	122,123
20	Streetlights	Commercial	Standard	9	1,923
21	Major Customer A	Commercial	Non-standard	3	41,106
22	Major Customer B	Commercial	Non-standard	2	28,324
23	Major Customer C	Commercial	Non-standard	2	16,720
24	Major Customer D	Commercial	Non-standard	2	12,451
25	*Add extra rows for additional consumer groups or price category codes as necessary*				
26			**Standard consumer totals**	46,954	552,145
27			**Non-standard consumer totals**	9	98,601
28			**Total for all consumers**	46,963	650,746

Billed quantities by price component

Price component	00700-1100	1700-2200	2400-0700	Anytime	Day	Econo	M/W Light	Night	Off Peak	Peak	Priority Econo
Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh
Business				108,787,217		6,537,927					
3 Rate									2,738,017	1,167,012	
Standard Domestic				164,175,575		43,438,179					
Low User Domestic				76,378,774		24,875,879					
Prepaid Domestic											
Time Of Use	25,599,028	39,395,643	27,887,405						29,241,213		
Streetlights							63,726				
Major Customer A											
Major Customer B											
Major Customer C											
Major Customer D											
Standard consumer totals	25,599,028	39,395,643	27,887,405	349,341,566	–	74,851,985	63,726	–	31,979,230	1,167,012	–
Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–	–
Total for all consumers	25,599,028	39,395,643	27,887,405	349,341,566	–	74,851,985	63,726	–	31,979,230	1,167,012	–

Price component	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	kVA	kVArh	Day	Month
Business								443,228		239,685	484,990	
3 Rate												
Standard Domestic								1,804,188			1,941,158	
Low User Domestic								1,312,180			2,230,485	
Prepaid Domestic												
Time Of Use									398,748	6,591,148		6,038
Streetlights				1,859,056								
Major Customer A							41,106,000					
Major Customer B							28,324,000					
Major Customer C							16,720,000					
Major Customer D							12,451,000					
Standard consumer totals	–	–	–	1,859,056	–	–	–	3,559,597	398,748	6,830,833	4,656,633	6,038
Non-standard consumer totals	–	–	–	–	–	–	98,601,000	–	–	–	–	–
Total for all consumers	–	–	–	1,859,056	–	–	98,601,000	3,559,597	398,748	6,830,833	4,656,633	6,038

Add extra columns for additional billed quantities by price component as necessary

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)
37	Business	Commercial	Standard	$13,422	$2,476	$13,422	–
38	3 Rate	Commercial	Standard	$355	$66	$355	–
39	Standard Domestic	Residential	Standard	$22,428	$4,138	$22,428	–
40	Low User Domestic	Residential	Standard	$12,211	$2,252	$12,211	–
41	Prepaid Domestic	Residential	Standard	–	–	–	–
42	Time Of Use	Commercial	Standard	$8,918	$1,646	$8,918	–
43	Streetlights	Commercial	Standard	$740	$137	$740	–
44	Major Customer A	Industrial	Non-standard	$1,147	$110	$1,147	–
45	Major Customer B	Industrial	Non-standard	$1,520	$100	$1,520	–
46	Major Customer C	Industrial	Non-standard	$453	$70	$453	–
47	Major Customer D	Industrial	Non-standard	$592	$70	$592	–
48			**Standard consumer totals**	$58,074	$10,714	$58,074	–
49			**Non-standard consumer totals**	$3,713	$350	$3,713	–
50			**Total for all consumers**	$61,787	$11,064	$61,787	–

Line charge revenues ($000) by price component

ʾrice component	0700-1100	1700-2200	2400-0700	Anytime	Day	Econo	M/W Light	Night	Off Peak	Peak	Priority Econo
Rate (eg, $ per day, $ per kWh, etc.)	0.05	0.03	0.01	0.09	0.00	0.03	0.10	0.00	0.02	0.16	0.00
Business				$9,677		$292					
3 Rate									$165	$190	
Standard Domestic				$12,689		$440					
Low User Domestic				$9,223		$1,309					
Prepaid Domestic											
Time Of Use	$1,189	$1,273	$305						$452		
Streetlights							$7				
Major Customer A											
Major Customer B											
Major Customer C											
Major Customer D											
Standard consumer totals	$1,189	$1,273	$305	$31,589	–	$2,041	$7	–	$617	$190	–
Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–	–
Total for all consumers	$1,189	$1,273	$305	$31,589	–	$2,041	$7	–	$617	$190	–

ʾrice component	Peak Saver	Prepay	Summer Peak	Streetlight	Thrifty Night	Winter Peak	Annual Contract	Export	Demand	Reactive	Supply	Transformer
Rate (eg, $ per day, $ per kWh, etc.)	0.00	0.00	0.00	0.39	0.00	0.00	0.04	0.01	8.99	0.05	3.09	297.71
Business								$4		$12	$3,438	
3 Rate												
Standard Domestic								$16			$9,283	
Low User Domestic								$11			$1,667	
Prepaid Domestic												
Time Of Use									$3,585	$317		$1,798
Streetlights				$733								
Major Customer A							$1,147					
Major Customer B							$1,520					
Major Customer C							$453					
Major Customer D							$592					
Standard consumer totals	–	–	–	$733	–	–	–	$31	$3,585	$329	$14,388	$1,798
Non-standard consumer totals	–	–	–	–	–	–	$3,713	–	–	–	–	–
Total for all consumers	–	–	–	$733	–	–	$3,713	$31	$3,585	$329	$14,388	$1,798

Add extra columns for additional line charge revenues by price component as necessary

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	9	**Check**	**OK**

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2023**
Network / Sub-network Name	

SCHEDULE 9a: ASSET REGISTER

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

sch ref

8	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
9	All	Overhead Line	Concrete poles / steel structure	No.	26,110	26,076	(34)	3
10	All	Overhead Line	Wood poles	No.	1,803	1,818	15	3
11	All	Overhead Line	Other pole types	No.	85	74	(11)	3
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	71	54	(18)	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	66	66	0	4
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	2	1	(1)	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	N/A
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	N/A
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	0	0	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.	6	5	(1)	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	4	5	1	4
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	5	5	–	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	15	15	–	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	4
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	29	27	(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	11	(1)	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	97	104	7	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.	17	18	1	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1,467	1,485	18	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	275	311	37	3
39	HV	Distribution Cable	Distribution UG PILC	km	7	7	1	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	2	2	–	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	40	36	(4)	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.	5,107	5,152	45	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.	357	414	57	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	3,195	3,187	(8)	3
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	983	1,037	54	3
48	HV	Distribution Transformer	Voltage regulators	No.	15	15	–	3
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	972	1,029	57	3
50	LV	LV Line	LV OH Conductor	km	705	690	(15)	3
51	LV	LV Cable	LV UG Cable	km	876	898	23	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	46	53	7	3
53	LV	Connections	OH/UG consumer service connections	No.	48,456	48,892	436	3
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	186	197	11	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	19	17	(2)	3
57	All	Load Control	Centralised plant	Lot	6	7	1	4
58	All	Load Control	Relays	No	3,217	3,027	(190)	3
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

Company Name: **Counties Energy Limited**
For Year Ended: **31 March 2023**
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)**

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	2021	2022	2023	No. with age unknown	Items at end of year	No. with default dates	Data accuracy (1–4)
9																																							
10	All	Overhead Line	Concrete poles / steel structure	No.	16	21	161	1,753	3,118	5,649	6,303	227	708	349	267	345	312	401	316	411	514	322	317	253	140	231	131	118	1,214	541	270	374	526	503	258	7	26,076		3
11	All	Overhead Line	Wood poles	No.	–	1	4	46	109	89	469	25	11	10	1	4	4	5	2	5	13	3	5	6	3	5	6	4	844	136	3	–	1	1	–	3	1,818		3
12	All	Overhead Line	Other pole types	No.	–	–	5	15	9	2	1	–	–	–	–	–	–	–	1	–	–	–	–	–	–	4	–	–	22	–	–	–	2	–	–	13	74		3
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	–	–	16	15	7	–	–	–	–	–	14	0	–	–	–	–	–	0	–	–	–	–	–	1	–	–	–	–	0	–	–	54		4
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	4	–	–	–	–	0	18	–	6	–	–	–	0	20	–	–	–	–	–	–	–	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	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0	–	–	–	–	–	0		4
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	–	–	1	3	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	5		4
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	–	1	–	–	–	–	–	–	1	–	–	0	–	–	–	–	1	–	–	–	–	1	–	–	1	–	–	5		4
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	5	–	–	–	–		5		4
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	9	6	–	–	–	–	–	–	–	–	–	15		4
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	–	10	–	7	1	–	–	–	–	–	3	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	6	–	–	–	27		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.	–	–	–	–	–	2	–	–	–	–	–	1	–	–	–	–	–	–	–	4	–	1	–	–	2	–	–	1	–	–	–	–	11		4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	4	–	16	12	–	–	–	–	–	–	11	–	–	–	–	–	–	–	22	–	–	–	–	26	–	–	13	–	–	104		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.	–	–	–	4	1	2	2	–	–	–	–	–	–	2	–	–	–	–	–	–	–	2	–	–	–	–	2	2	–	1	–	–	18		4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	26	42	70	211	225	292	265	19	18	29	17	9	12	24	12	9	28	19	13	10	8	8	5	8	14	30	4	20	23	10	3	0	1,485		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	4	6	2	2	7	8	15	10	2	9	11	8	9	9	15	14	9	11	12	24	28	39	28	5	0	311		3
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	0	–	2	4	–	0	–	1	–	–	0	0	–	–	–	–	–	–	0	–	0	–	–	–	0	–	–	–	–	7		3
41	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	0	–	–	–	–	1	–	–	–	–	–	0	0	–	–	–	2		4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionaliser	No.	–	–	–	–	–	1	2	2	1	–	–	–	–	–	3	1	–	–	–	–	8	2	–	–	1	6	2	4	1	1	1	–	36		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.	–	–	15	48	158	418	1,044	195	153	103	110	98	137	53	128	81	96	230	230	185	255	160	153	137	129	188	128	74	125	168	72	81	5,152		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.	–	–	–	–	1	3	11	3	3	1	6	4	–	4	8	8	10	9	10	13	2	4	4	6	26	31	49	69	48	61	13	7	414		3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	–	13	20	90	234	502	61	86	61	81	81	91	40	84	37	48	171	197	158	220	128	130	102	74	125	72	42	71	106	49	13	3,187		3
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	–	2	3	15	128	25	20	17	25	20	25	28	23	29	17	36	45	27	59	47	42	41	59	58	61	42	64	59	15	5	1,037		3
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–	–	–	1	1	–	–	–	8	3	–	–	–	–	15		3
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	4	4	11	126	25	20	17	25	20	26	29	23	29	17	36	45	27	59	49	42	39	57	55	59	39	65	60	15	6	1,029		3
51	LV	LV Line	LV OH Conductor	km	0	0	1	1	3	3	620	6	4	6	3	2	4	2	1	3	4	1	4	1	3	2	1	0	1	2	2	0	5	2	1	2	690		3
52	LV	LV Cable	LV UG Cable	km	–	–	1	1	9	4	223	25	19	21	16	15	35	42	22	14	7	20	12	22	18	39	27	34	42	46	35	37	39	43	12	19	898		3
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	–	–	–	0	0	0	2	0	0	1	1	1	0	1	1	1	2	8	5	5	6	6	0	2	1	2	2	5	1	1	53		3
54	LV	Connections	OH/UG consumer service connections	No.	–	–	–	1	–	11,789	14,198	1,114	532	595	884	976	1,003	842	877	884	602	589	503	497	683	891	869	1,243	1,225	986	1,051	2,478	1,348	1,707	436	89	48,892		3
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	5	8	4	18	2	–	–	–	2	–	–	16	–	–	–	–	4	2	–	17	38	–	12	–	26	26	–	17	–	–	197		3
56	All	SCADA and communications	SCADA and communications equipment operating as a single sys	Lot	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	1		4
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	12	–	–	–	–	–	3	1	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	17		3
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	2	1	–	–	–	–	–	–	1	–	–	–	–	–	–	–	1	–	–	–	–	–	1	–	–	1	–	7		4
59	All	Load Control	Relays	No	–	–	–	–	–	–	293	527	341	256	313	225	163	104	115	110	19	37	55	99	213	52	105	–	–	–	–	–	–	–	–	–	3,027		3
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2023**
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

Circuit length by operating voltage (at year end)	Overhead (km)	Underground (km)	Total circuit length (km)
> 66kV	66	0	66
50kV & 66kV	–	–	–
33kV	54	1	55
SWER (all SWER voltages)	–	–	–
22kV (other than SWER)	586	250	836
6.6kV to 11kV (inclusive—other than SWER)	899	101	1,000
Low voltage (< 1kV)	690	898	1,588
Total circuit length (for supply)	2,294	1,251	3,545
Dedicated street lighting circuit length (km)		53	53
Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			2

Overhead circuit length by terrain (at year end)	Circuit length (km)	(% of total overhead length)
Urban	169	7%
Rural	2,061	90%
Remote only	–	–
Rugged only	64	3%
Remote and rugged	–	–
Unallocated overhead lines	–	–
Total overhead length	2,294	100%

	Circuit length (km)	(% of total circuit length)
Length of circuit within 10km of coastline or geothermal areas (where known)	1,608	45%

	Circuit length (km)	(% of total overhead length)
Overhead circuit requiring vegetation management	2,294	100%

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2023**

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 *	Average number of ICPs in disclosure year	Line charge revenue ($000)
8			
9	Counties Energy 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 Energy Limited**
For Year Ended	**31 March 2023**
Network / Sub-network Name	

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref				
8	**9e(i): Consumer Connections and Decommissionings**			
9	*Number of ICPs connected during year by consumer type*			
10	*Consumer types defined by EDB**		**Number of connections (ICPs)**	
11	Urban Residential		546	
12	Urban Commercial		293	
13	Rural Residential		333	
14	Rural Commercial		259	
15				
16	** include additional rows if needed*			
17	**Connections total**		1,431	
18				
19	*Number of ICPs decommissioned during year by consumer type*			
20	*Consumer types defined by EDB**		**Number of decommissionings**	
21	Urban Residential		118	
22	Urban Commercial		42	
23	Rural Residential		96	
24	Rural Commercial		62	
25				
26	** include additional rows if needed*			
27	**Decommissionings total**		318	
28				
29	**Distributed generation**			
30	Number of connections made in year		273	**connections**
32	Capacity of distributed generation installed in year		1.95	**MVA**
33				
34	**9e(ii): System Demand**			
35				
36			**Demand at time of maximum coincident demand (MW)**	
37	**Maximum coincident system demand**			
38	GXP demand		126	
39	Distributed generation output at HV and above	*plus*	8	
40	**Maximum coincident system demand**		134	
41	Net transfers to (from) other EDBs at HV and above	*less*		
42	**Demand on system for supply to consumers' connection points**		134	
43	**Electricity volumes carried**		**Energy (GWh)**	
44	Electricity supplied from GXPs		633	
45	Electricity exports to GXPs	*less*		
46	Electricity supplied from distributed generation	*plus*	49	
47	Net electricity supplied to (from) other EDBs	*less*		
48	**Electricity entering system for supply to consumers' connection points**		682	
49	Total energy delivered to ICPs	*less*	651	
51	**Electricity losses (loss ratio)**		32	4.6%
52				
53	**Load factor**		0.58	
54	**9e(iii): Transformer Capacity**			
55			**(MVA)**	
56	Distribution transformer capacity (EDB owned)		436	
57	Distribution transformer capacity (Non-EDB owned, estimated)		66	
58	**Total distribution transformer capacity**		502	
59				
60	**Zone substation transformer capacity**		545	
61				

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2023**
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 this 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)	–	
11	Class B (planned interruptions on the network)	422	
12	Class C (unplanned interruptions on the network)	546	
13	Class D (unplanned interruptions by Transpower)	–	
14	Class E (unplanned interruptions of EDB owned generation)	–	
15	Class F (unplanned interruptions of generation owned by others)	–	
16	Class G (unplanned interruptions caused by another disclosing entity)	–	
17	Class H (planned interruptions caused by another disclosing entity)	–	
18	Class I (interruptions caused by parties not included above)	83	
19	**Total**	1,051	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	289	257
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.77	228.3
27	Class C (unplanned interruptions on the network)	3.20	297.8
28	Class D (unplanned interruptions by Transpower)	–	–
29	Class E (unplanned interruptions of EDB owned generation)	–	–
30	Class F (unplanned interruptions of generation owned by others)	–	–
31	Class G (unplanned interruptions caused by another disclosing entity)	–	–
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	0.07	9.2
34	**Total**	4.04	535.4
35			
36	**Normalised SAIFI and SAIDI**	**Normalised SAIFI**	**Normalised SAIDI**
37	Classes B & C (interruptions on the network)	3.97	468.2
38			
39	**Transitional SAIDI and SAIDI (previous method)**	**SAIFI**	**SAIDI**
40	*Where EDBs do not currently record their SAIFI and SAIDI values using the 'multi-count' approach, they shall continue to record their SAIFI and SAIDI values on the same basis that they employed as at 31 March 2023 as 'Transitional SAIFI' and 'Transitional SAIDI' values, in addition to their SAIFI and SAIDI values (Classes B & C) using the 'multi-count approach'.* ***This is a transitional reporting requirement that shall be in place for the 2024, 2025, and 2026 disclosure years.***		
41	Class B (planned interruptions on the network)	N/A	N/A
42	Class C (unplanned interruptions on the network)	N/A	N/A

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2023**
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 this ID determination), and so is subject to the assurance report required by section 2.8.

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

Cause	SAIFI	SAIDI
Lightning	0.05	3.8
Vegetation	0.90	114.3
Adverse weather	0.01	1.0
Adverse environment	0.02	16.0
Third party interference	0.36	54.8
Wildlife	0.19	5.0
Human error	0.18	2.5
Defective equipment	0.74	68.8
Cause unknown	0.75	31.7

Breakdown of third party interference	SAIFI	SAIDI
Dig-in	N/A	N/A
Overhead contact	N/A	N/A
Vandalism	N/A	N/A
Vehicle damage	N/A	N/A
Other	N/A	N/A

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	–	–
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	0.53	175.0
Distribution cables (excluding LV)	0.20	49.8
Distribution other (excluding LV)	0.04	3.5

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.42	19.4
Subtransmission cables		–
Subtransmission other	0.25	5.2
Distribution lines (excluding LV)	2.30	246.9
Distribution cables (excluding LV)	0.04	1.7
Distribution other (excluding LV)	0.18	24.6

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	20	120	16.69
Subtransmission cables	–	1	–
Subtransmission other	5		
Distribution lines (excluding LV)	494	1,485	33.27
Distribution cables (excluding LV)	6	351	1.71
Distribution other (excluding LV)	33		0
Total	558		

Company Name	Counties Energy Limited
For Year Ended	31 March 2023

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 9.62% in FY22 to 8.46% in FY23 with the following items of note:

- Revenue increased by 9.6% in FY23 to $61.8m (FY22 - $56.4m);
- Operational costs increased from 34% of lines revenue in FY22 to 40% of lines revenue (2% Network Spend, 4% Business Support);
- Revaluations increased from $22.8m in FY22 (6.9% CPI) to $24.8m in FY23 (6.7% CPI).
- Depreciation increased from $12.1m in FY22 to $13.4m in FY23 reflecting continued high network growth.
- Commissioned assets in FY23 were $41.7m (FY22 - $34.0m).

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. The revaluation uplift was $24.8m reflecting the CPI of 6.7% in FY23. Commissioned assets in FY23 were $41.7m (FY22 - $34.0m). Assets being disposed of comprise non-system vehicles and minor plant and IT equipment/software ($381k) and transformers sold as scrap ($156k). A loss of $448k was recorded for these disposals. Higher depreciation in FY23 reflects continued high network growth and investment in IT related assets to support the network.

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 ($99k), entertainment expense ($49k) and other ($6k).

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 ($8k).

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
12.1: Consumer types are based on historical AMP descriptions. Treatment for all other categories was to sum the many small projects (>$50k) by significant core drivers. 12.2: 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. There is no atypical expenditure.

Variance between forecast and actual expenditure (Schedule 7)

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

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

7(i): Line charge revenue finished near to target.

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

•Consumer connections were $9.1m (65%) above target due to the continued high number of residential and large commercial connections;

•System growth was $11.4m (93%) below target due to deferral of land purchases for substations and related upgrades;

•Asset replacement and renewal was $3.5m (11%) below target due largely to deferral of work related to substation rebuilds;

•Quality of supply was $1.3m (73%) below target due to timing of 3 projects that were forecast to be completed in FY23 but will roll forward to FY24 onwards; and

•Expenditure on non-network assets was lower than forecast due to timing of the Glasgow site upgrade and IT projects carried over to FY24.

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

•Vegetation management was $0.3m (16%) above target due to Cyclone Gabrielle and other weather-related events along with a push to clear vegetation to reduce further damage on the network and improve reliability;

•Routine and corrective maintenance was $0.4m (20%) above target with the accelerated inspection programme to address SAIDI/SAIFI;

•Asset replacement and renewal was $0.7m (45%) below target with higher capitalisation of works through the year; and

•Business Support costs were $1.0m (10%) higher than target with increased Digital spend focused on the network and Marketing to enhance the Customer experience.

7(iv): Where justified by public safety and reliability, OHUG conversions are undertaken with the above target spend reflecting this.

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 within 2% of target for the year. ICP growth remained strong at 2.6% for the year.

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

In FY22, recording systems were updated to include outages impacting single transformers, which previously were interpreted as LV interruptions and excluded from class C disclosure. Consistent with FY22, our FY23 now includes these outages. This represents an additional 150 interruptions, 0.03 SAIFI and 8.30 SAIDI in class C before normalisation.

Schedules 10(iv) and 10(v) include faults where the original cause was recorded as low voltage but caused a consequential high voltage outage and therefore incurring SAIFI and SAIDI. This represents 54 faults, 0.05 SAIFI and 4.35 SAIDI. If these faults originating on LV Networks were excluded, the Distribution Lines fault rate would be 29.83 and the Distribution Cables fault rate 1.42.

Unplanned (class C) outages, as measured by SAIFI and SAIDI, returned an unfavourable result for FY23. Weather related events are having an increasing impact on reliability and impacting on other categories and in particular vegetation.

Consistent with prior years, Counties Energy has reallocated SAIFI / SAIDI arising from events initiating from privately owned network assets to Class I (0.05 SAIFI / 3.20 SAIDI has been reallocated from Class C with the balance in Class I moving from Class B where planned requests on privately owned networks impact more than one ICP).

Refer to schedule 15 for commentary on “Successive Interruptions”.

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 Energy Limited
For Year Ended	31 March 2023

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 3% 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 3% per annum.

Company Name	Counties Energy Limited
For Year Ended	31 March 2023

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.)

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

    5.1 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;

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

6. 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.

7. Provide additional explanatory comment in the box below.

Box 1: Voluntary explanatory comment on disclosed information

Successive Interruptions:

For FY23, Counties Energy has partially accepted the “Successive Interruption” exemption:

- Class B (planned) disclosure in Schedule 10 includes the full impact of “Successive Interruptions”. This is consistent with disclosures since FY21 (inclusive), with the enabling change to reporting for planned events having been implemented part way through FY20.

- Class C (unplanned) disclosure in schedule 10 remains consistent with prior years where Counties Energy 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. However, SAIFI has also been recalculated based on the alternative interpretation noting Class C (unplanned) SAIFI for FY23 would increase by 4.4% from 3.20 to 3.34 and normalised Class B and C (planned and unplanned) SAIFI by 3.5% from 3.97 to 4.11.

Network Reliability Information

During an 11 day period between the 12th of February and 23rd of February 2023, there were limitations in the ability to collect and record network reliability information. Unfortunately, this period coincided with the Cyclone Gabrielle event and its aftermath. Management are confident the information has been correctly disclosed in Schedules 10(i) to 10(iv) but have not been able to provide sufficient evidence required to support an unqualified opinion.

Useful Asset Lives (Schedule 4)

Weighted average remaining asset lives have a higher than usual variance to the preceding year following a review and write-off of $nil historical network assets. This update did not impact the carrying value of the Regulatory Asset Base.

Schedule 18 Certification for Year-end Disclosures

Clause 2.9.2

We, Vern Dark and Hamish Stevens, being directors of Counties Energy 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[(2)], and 14 has been properly extracted from Counties Energy 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.

Vern Dark	Hamish Stevens
23 August 2023	23 August 2023

(1) The Directors of Counties Energy Limited note the amendment to the ID Determination issued by the Commerce Commission on 26 May 2023 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 Energy 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.

(2) The Directors of Counties Energy Limited note that they are unable to provide certification on the SAIDI/SAIFI results due to the 11 day system limitation as outlined in box 1 of schedule 15.

Independent Assurance Report

To the Directors of Counties Energy Limited and to the Commerce Commission on the disclosure information for the disclosure year ended 31 March 2023 as required by the Electricity Distribution Information Disclosure Determination 2012 (Consolidated 6 July 2023)

Counties Energy Limited (the Company) is required to disclose certain information under the Electricity Distribution Information Disclosure Determination 2012 (consolidated 6 July 2023) (the Determination) and to procure an assurance report by an independent auditor in terms of section 2.8.1 of the Determination.

The Auditor-General is the auditor of the Company.

The Auditor-General has appointed me, Matthew White, using the staff and resources of PricewaterhouseCoopers, to undertake a reasonable assurance engagement, on his behalf, on whether the information prepared by the Company for the disclosure year ended 31 March 2023 (the Disclosure Information) complies, in all material respects, with the Determination.

The Disclosure Information that falls within the scope of the assurance engagement are:

- Schedules 1 to 4, 5a to 5g, 6a and 6b, 7, 10 and 14 (limited to the explanatory notes in boxes 1 to 11) of the Determination.
- Clause 2.3.6 of the Determination and clauses 2.2.11(1)(g) and 2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012 (consolidated 20 May 2020) (the IM Determination), in respect of the basis for valuation of related party transactions (the Related Party Transaction Information).

This assurance report should be read in conjunction with the Commerce Commission's Information Disclosure exemption, issued to all electricity distribution businesses on 26 May 2023 under clause 2.11.1 of the Determination. The Commerce Commission granted an exemption from the requirement that the assurance report, in respect of the information in Schedule 10 of the Determination, must take into account any issues arising out of the Company's recording of SAIDI, SAIFI, and number of interruptions due to successive interruptions.

Qualified Opinion

In our opinion, except for the possible effect of the matter described in the Basis for Qualified Opinion section of our report, in all material respects:

- as far as appears from an examination, 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, sourced from the Company's financial and non-financial systems;
- the Disclosure Information complies with the Determination; and
- the basis for valuation of related party transactions complies with the Determination and the IM Determination.

Basis for Qualified Opinion

We were unable to obtain sufficient appropriate evidence about the Company's network reliability information, required to be disclosed in Schedules 10(i) to 10(iv), throughout the period as required. This was a result of a monitoring system being offline for an 11 day period between the 12th February and 23rd February 2023. During this time there were a material number of interruptions impacting the SAIDI and SAIFI measures disclosed in Schedules 10(i) to 10(iv).

There were no practical audit procedures that we could adopt to independently confirm the completeness and accuracy of the ICP data used to record the number of ICPs affected and duration of the interruptions for the purposes of inclusion in the amounts relating to SAIDI and SAIFI interruptions statistics set out in Schedules 10(i) to 10(iv). Because of the potential effect of the limitations described above, we are unable to obtain sufficient appropriate evidence to confirm the accuracy of the data that forms the basis of the compilation of Schedules 10(i) to 10(iv), and therefore qualify our opinion in this regard.

We conducted our engagement in accordance with the Standard on Assurance Engagements (SAE) 3100 (Revised) Assurance Engagements on Compliance, issued by the New Zealand Auditing and Assurance Standards Board. An engagement conducted in accordance with SAE 3100 (Revised) requires that we comply with the International Standard on Assurance Engagements (New Zealand) 3000 (Revised) Assurance Engagements Other Than Audits or Reviews of Historical Financial Information.

We have obtained sufficient recorded evidence and explanations that we required to provide a basis for our qualified opinion.

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 IM Determination, 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. Due to the importance of the RAB within the regulatory regime, the incentives to overstate the RAB value, and complexities within the regulations, we have considered it to be a key area of focus.	We have obtained an understanding of the compliance requirements relevant to the RAB as set out in the Determination and the IM Determination. Our procedures over the regulatory asset base included the following: **Assets commissioned** ● We considered the nature of 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 Determination, which are required to be removed from the RAB; ● 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 Determination, which are required to be removed from the RAB; ● 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 material reconciling items; and ● We tested a sample of assets commissioned during the disclosure period for appropriate asset category classification. **Depreciation** ● For assets with no standard asset lives we assessed the reasonableness of the lives used by reference to the accounting depreciation rates used in preparing the financial statements;

Key Assurance Matter	How our procedures addressed the key assurance matter
	• We have performed a reasonableness test to ensure regulatory depreciation expense is calculated in line with IM Determination clause 2.2.5 • We compared the spreadsheet formula utilised to calculate regulatory depreciation expense with IM Determination clause 2.2.5; and • We compared the standard asset lives by asset category to those set out in the IM Determination. **Revaluation** • We verified the spreadsheet formula utilised to calculate regulatory depreciation expense is in line with IM Determination clause 2.2.5; • We recalculated the revaluation rate set out in the IM Determination using the relevant Consumer Price Index indices taken from the Statistics New Zealand website; and • We tested the mathematical accuracy of the revaluation calculation performed by management. **Disposals** • We reconciled the disposals, as per the regulatory fixed asset register, to the asset disposals disclosed in the audited annual financial statements and investigated any material reconciling items; and • 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;
Cost and Asset Allocation The Determination relates to information concerning the supply of electricity distribution services. In addition to the regulated supply of electricity, the Company also supplies customers with other unregulated services such as metering services. As set out in schedules 5d, 5e, 5f and 5g, costs and asset values that relate to electricity distribution services regulated under the 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 IM Determination set out rules and processes for allocating costs and assets which are not directly attributable to either regulated or unregulated services. A number of screening tests apply which must be considered when deciding on the appropriate allocation method.	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 transactions to ensure their classification as either directly attributable or not directly attributable costs are appropriate and in line with the Determination, as amended; • Inspecting the fixed asset register to identify any asset classes which based on their nature and our understanding of the business could be considered assets directly attributable to a specific business unit; • Testing a sample of assets commissioned to ensure their classification as either directly attributable or not directly attributable are appropriate and in line with the Determination, as amended, by inspecting the related invoice;

Key Assurance Matter	How our procedures addressed the key assurance matter
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.	**Appropriateness of the allocators used for not directly attributable costs and assets** ● Considering the appropriateness of the cost and asset causal and proxy allocators used in applying the ABAA to not directly attributable costs including inspecting supporting documentation and recalculating proxy allocators; ● Understanding why causal relationships could not be identified in allocating some costs or assets and ensuring appropriate disclosure has been included outlining these in Schedule 14; ● Recalculating the split between not directly attributable costs and asset values allocated to electricity distribution services and non-electricity distribution services.

Directors' responsibilities
The directors of the Company are responsible in accordance with the Determination for:

- the preparation of the Disclosure Information; and
- the Related Party Transaction Information

The directors of the Company are also responsible for the identification of risks that may threaten compliance with the schedules and clauses identified above and controls which will mitigate those risks and monitor ongoing compliance.

Auditor's responsibilities
Our responsibilities in terms of clauses 2.8.1(1)(b)(vi) and (vii), 2.8.1(1)(c) and 2.8.1(1)(d) are to express an opinion on whether, in all material respects:

- as far as appears from an examination, the information used in the preparation of the audited Disclosure Information has been properly extracted from the Company's accounting and other records, sourced from its financial and non-financial systems;
- as far as appears from an examination, proper records to enable the complete and accurate compilation of the audited Disclosure Information required by the Determination have been kept by the Company and, if not, the records not so kept;
- the Company complied, in all material respects, with the Determination in preparing the audited Disclosure Information; and
- the Company's basis for valuation of related party transactions in the disclosure year has complied, in all material respects, with clause 2.3.6 of the Determination and clauses 2.2.11(1)(g) and 2.2.11(5) of the IM Determination.

To meet these responsibilities, we planned and performed procedures in accordance with SAE 3100 (Revised), to obtain reasonable assurance about whether the Company has complied, in all material respects, with the Disclosure Information (which includes the Related Party Transaction Information) required to be audited by the Determination. An assurance engagement to report on the Company's compliance with the Determination involves performing procedures to obtain evidence about the compliance activity and controls implemented to meet the requirements. The procedures selected depend on our judgement, including the identification and assessment of the risks of material non-compliance with the requirements.

Inherent limitations

Because of the inherent limitations of an assurance engagement, together with the internal control structure, it is possible that fraud, error or non-compliance with the Determination may occur and not be detected. A reasonable assurance engagement throughout the disclosure year does not provide assurance on whether compliance with the Determination will continue in the future.

Restricted use

This report has been prepared for use by the directors of the Company and the Commerce Commission in accordance with clause 2.8.1(1)(a) of the Determination and is provided solely for the purpose of establishing whether the compliance requirements have been met. We disclaim any assumption of responsibility for any reliance on this report to any person other than the directors of the Company and the Commerce Commission, or for any other purpose than that for which it was prepared.

Independence and quality control

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

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 trading activities of the Company, this engagement, and the annual audit of the Company's financial statements and performance information, we have no relationship with, or interests in, the Company.

Matthew White
On behalf of the Auditor-General
Hamilton, New Zealand
30 August 2023

PricewaterhouseCoopers