Counties Energy

Information Disclosure prepared in accordance with the

Electricity Distribution Information Disclosure Determination 2012

For the Year Ended 31 March 2022

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Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2022**

SCHEDULE 1: ANALYTICAL RATIOS

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

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

sch ref

7 ## 1(i): Expenditure metrics

sch ref		Expenditure per GWh energy delivered to ICPs ($/GWh)	Expenditure per average no. of ICPs ($/ICP)	Expenditure per MW maximum coincident system demand ($/MW)	Expenditure per km circuit length ($/km)	Expenditure per MVA of capacity from EDB-owned distribution transformers ($/MVA)
8						
9	**Operational expenditure**	28,966	415	146,927	5,429	27,342
10	Network	10,249	147	51,988	1,921	9,675
11	Non-network	18,717	268	94,938	3,508	17,668
12						
13	**Expenditure on assets**	94,402	1,353	478,836	17,695	89,109
14	Network	85,149	1,220	431,904	15,960	80,376
15	Non-network	9,253	133	46,932	1,734	8,734
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**	85,899	1,231
20	Standard consumer line charge revenue	97,674	1,160
21	Non-standard consumer line charge revenue	28,894	360,567
22			

23 ## 1(iii): Service intensity measures

sch ref			
24			
25	Demand density	37	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
26	Volume density	187	*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	14,329	*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	19,003	33.67%
33	Pass-through and recoverable costs excluding financial incentives and wash-ups	12,529	22.20%
34	Total depreciation	12,097	21.43%
35	Total revaluations	22,796	40.39%
36	Regulatory tax allowance	3,769	6.68%
37	Regulatory profit/(loss) including financial incentives and wash-ups	31,836	56.41%
38	**Total regulatory income**	56,437	
39			

40 ## 1(v): Reliability

sch ref			
41			
42	Interruption rate	23.54	*Interruptions per 100 circuit km*

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For Year Ended	**31 March 2022**

SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

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

2(i): Return on Investment

	CY-2	CY-1	Current Year CY
	31 Mar 20	31 Mar 21	31 Mar 22
ROI – comparable to a post tax WACC	%	%	%
Reflecting all revenue earned	5.88%	3.69%	9.62%
Excluding revenue earned from financial incentives	5.88%	3.69%	9.62%
Excluding revenue earned from financial incentives and wash-ups	5.88%	3.69%	9.62%
Mid-point estimate of post tax WACC	4.27%	3.72%	3.52%
25th percentile estimate	3.59%	3.04%	2.84%
75th percentile estimate	4.95%	4.40%	4.20%
ROI – comparable to a vanilla WACC			
Reflecting all revenue earned	6.31%	4.02%	9.92%
Excluding revenue earned from financial incentives	6.31%	4.02%	9.92%
Excluding revenue earned from financial incentives and wash-ups	6.31%	4.02%	9.92%
WACC rate used to set regulatory price path			
Mid-point estimate of vanilla WACC	4.69%	4.05%	3.82%
25th percentile estimate	4.01%	3.37%	3.14%
75th percentile estimate	5.37%	4.73%	4.50%

2(ii): Information Supporting the ROI

			($000)	
	Total opening RAB value	330,036		
plus	Opening deferred tax	(19,379)		
Opening RIV			310,657	
Line charge revenue			56,353	
	Expenses cash outflow	31,532		
add	Assets commissioned	33,968		
less	Asset disposals	225		
add	Tax payments	1,545		
less	Other regulated income	84		
Mid-year net cash outflows			66,736	
Term credit spread differential allowance			–	
	Total closing RAB value	374,478		
less	Adjustment resulting from asset allocation	(0)		
less	Lost and found assets adjustment	–		
plus	Closing deferred tax	(21,603)		
Closing RIV			352,875	
ROI – comparable to a vanilla WACC				9.92%
	Leverage (%)			42%
	Cost of debt assumption (%)			2.55%
	Corporate tax rate (%)			28%
ROI – comparable to a post tax WACC				9.62%

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

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sch ref

2(iii): Information Supporting the Monthly ROI

Opening RIV	N/A

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

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

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

Year-end ROI – comparable to a vanilla WACC	9.72%
Year-end ROI – comparable to a post tax WACC	9.42%

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

2(v): Financial Incentives and Wash-Ups

Net recoverable costs allowed under incremental rolling incentive scheme	–	
Purchased assets – avoided transmission charge		
Energy efficiency and demand incentive allowance		
Quality incentive adjustment		
Other financial incentives		
Financial incentives		–
Impact of financial incentives on ROI		–
Input methodology claw-back		
CPP application recoverable costs		
Catastrophic event allowance		
Capex wash-up adjustment		
Transmission asset wash-up adjustment		
2013–15 NPV wash-up allowance		
Reconsideration event allowance		
Other wash-ups		
Wash-up costs		–
Impact of wash-up costs on ROI		–

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2022**

SCHEDULE 3: REPORT ON REGULATORY PROFIT

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

sch ref				
7		**3(i): Regulatory Profit**		**($000)**
8		**Income**		
9		Line charge revenue		56,353
10	*plus*	Gains / (losses) on asset disposals		(138)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)		222
12				
13		**Total regulatory income**		56,437
14		**Expenses**		
15	*less*	Operational expenditure		19,003
16				
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups		12,529
18				
19		**Operating surplus / (deficit)**		24,905
20				
21	*less*	Total depreciation		12,097
22				
23	*plus*	Total revaluations		22,796
24				
25		**Regulatory profit / (loss) before tax**		35,604
26				
27	*less*	Term credit spread differential allowance		–
28				
29	*less*	Regulatory tax allowance		3,769
30				
31		**Regulatory profit/(loss) including financial incentives and wash-ups**		31,836
32				
33		**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	**($000)**	
34		**Pass through costs**		
35		Rates	721	
36		Commerce Act levies	100	
37		Industry levies	123	
38		CPP specified pass through costs		
39		**Recoverable costs excluding financial incentives and wash-ups**		
40		Electricity lines service charge payable to Transpower	10,964	
41		Transpower new investment contract charges		
42		System operator services		
43		Distributed generation allowance	621	
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**		12,529
47				

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2022**

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 21**	**31 Mar 22**
51	Allowed controllable opex			
52	Actual controllable opex			
53				
54	Incremental change in year			
55				
56			**Previous years' incremental change**	**Previous years' incremental change adjusted for inflation**
57	CY-5	31 Mar 17		
58	CY-4	31 Mar 18		
59	CY-3	31 Mar 19		
60	CY-2	31 Mar 20		
61	CY-1	31 Mar 21		
62	**Net incremental rolling incentive scheme**			–
63				
64	**Net recoverable costs allowed under incremental rolling incentive scheme**			–
65	**3(iv): Merger and Acquisition Expenditure**			
70				**($000)**
66	Merger and acquisition expenditure			
67				
68	*Provide commentary on the benefits of merger and acquisition expenditure to the electricity distribution business, including required disclosures in accordance with section 2.7, in Schedule 14 (Mandatory Explanatory Notes)*			
69	**3(v): Other Disclosures**			
70				**($000)**
71	Self-insurance allowance			

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2022**

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

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

sch ref

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

		RAB	RAB	RAB	RAB	RAB
	for year ended	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**
		($000)	**($000)**	**($000)**	**($000)**	**($000)**
Total opening RAB value		241,528	253,205	270,478	287,274	330,036
less **Total depreciation**		7,899	8,228	9,353	10,565	12,097
plus **Total revaluations**		2,661	3,754	6,847	4,364	22,796
plus **Assets commissioned**		16,432	22,431	19,344	49,142	33,968
less **Asset disposals**		108	92	42	179	225
plus **Lost and found assets adjustment**						–
plus **Adjustment resulting from asset allocation**		593	(592)			(0)
Total closing RAB value		253,205	270,478	287,274	330,036	374,478

4(ii): Unallocated Regulatory Asset Base

	Unallocated RAB *		RAB	
	($000)	($000)	($000)	($000)
Total opening RAB value		331,328		330,036
less				
Total depreciation		12,283		12,097
plus				
Total revaluations		22,886		22,796
plus				
Assets commissioned (other than below)	34,180		33,968	
Assets acquired from a regulated supplier	–		–	
Assets acquired from a related party	–		–	
Assets commissioned		34,180		33,968
less				
Asset disposals (other than below)	240		225	
Asset disposals to a regulated supplier	–		–	
Asset disposals to a related party	–		–	
Asset disposals		240		225
plus **Lost and found assets adjustment**				
plus **Adjustment resulting from asset allocation**				(0)
Total closing RAB value		375,871		374,478

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

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

CPI_4	1,142
CPI_4^{-4}	1,068
Revaluation rate (%)	6.93%

	Unallocated RAB *		RAB	
	($000)	**($000)**	**($000)**	**($000)**
Total opening RAB value	331,328		330,036	
less Opening value of fully depreciated, disposed and lost assets	1,027		1,027	
Total opening RAB value subject to revaluation	330,301		329,009	
Total revaluations		22,886		22,796

4(iv): Roll Forward of Works Under Construction

	Unallocated works under construction		Allocated works under construction	
Works under construction—preceding disclosure year		18,875		18,875
plus Capital expenditure	36,479		36,268	
less Assets commissioned	34,180		33,968	
plus Adjustment resulting from asset allocation				
Works under construction - current disclosure year		21,174		21,175
Highest rate of capitalised finance applied				2.33%

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2022**

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

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

sch ref

76 ### 4(v): Regulatory Depreciation

sch ref		Unallocated RAB * ($000)	Unallocated RAB * ($000)	RAB ($000)	RAB ($000)
79	Depreciation - standard	9,604		9,604	
80	Depreciation - no standard life assets	2,679		2,493	
81	Depreciation - modified life assets				
82	Depreciation - alternative depreciation in accordance with CPP				
83	**Total depreciation**		12,283		12,097
84					

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

($000 unless otherwise specified)

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

95 ** include additional rows if needed*

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

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

sch ref			Subtransmission lines	Subtransmission cables	Zone substations	Distribution and LV lines	Distribution and LV cables	Distribution substations and transformers	Distribution switchgear	Other network assets	Non-network assets	Total
99		**Total opening RAB value**	17,154	213	50,380	116,200	48,544	42,492	18,402	5,651	31,000	330,036
100	*less*	Total depreciation	469	8	1,329	3,115	1,624	1,635	818	540	2,559	12,097
101	*plus*	Total revaluations	1,189	15	3,490	8,051	3,364	2,936	1,273	391	2,087	22,796
102	*plus*	Assets commissioned	335	–	8,071	10,148	1,051	2,215	5,352	726	6,070	33,968
103	*less*	Asset disposals	–	–	–	–	–	106	–	–	119	225
104	*plus*	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
105	*plus*	Adjustment resulting from asset allocation	–	–	–	–	–	–	–	–	–	–
106	*plus*	Asset category transfers	–	–	–	–	–	–	–	–	–	–
107		**Total closing RAB value**	18,209	220	60,612	131,284	51,335	45,902	24,209	6,228	36,479	374,478
108												
109		**Asset Life**										
110		Weighted average remaining asset life	46.4	25.0	45.0	51.4	39.2	34.7	35.0	9.7	12.2	(years)
111		Weighted average expected total asset life	60.0	44.8	45.0	60.0	58.4	45.0	35.0	14.5	15.9	(years)

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

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

sch ref					
7		**5a(i): Regulatory Tax Allowance**			**($000)**
8		**Regulatory profit / (loss) before tax**			35,604
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	26	*	
12		Amortisation of initial differences in asset values	2,663		
13		Amortisation of revaluations	1,249		
14					3,938
15					
16	*less*	Total revaluations	22,796		
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	3,286		
21					26,082
22					
23		**Regulatory taxable income**			13,461
24					
25	*less*	Utilised tax losses			
26		Regulatory net taxable income			13,461
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**			3,769
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	66,576		
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	1		
40		Closing unamortised initial differences in asset values			63,912
41					
42		Opening weighted average remaining useful life of relevant assets (years)			25
43					

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

This schedule requires information on the calculation of the regulatory tax allowance. This information is used to calculate regulatory profit/loss in Schedule 3 (regulatory profit). EDBs must provide explanatory commentary on the information disclosed in this schedule, in Schedule 14 (Mandatory Explanatory Notes).
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sch ref				
44	**5a(iv): Amortisation of Revaluations**			**($000)**
45				
46		Opening sum of RAB values without revaluations	296,693	
47				
48		Adjusted depreciation	10,848	
49		Total depreciation	12,097	
50		Amortisation of revaluations		1,249
51				
52	**5a(v): Reconciliation of Tax Losses**			**($000)**
53				
54		**Opening tax losses**		
55	*plus*	Current period tax losses		
56	*less*	Utilised tax losses		
57		**Closing tax losses**		–
58	**5a(vi): Calculation of Deferred Tax Balance**			**($000)**
59				
60		**Opening deferred tax**	(19,379)	
61				
62	*plus*	Tax effect of adjusted depreciation	3,037	
63				
64	*less*	Tax effect of tax depreciation	4,708	
65				
66	*plus*	Tax effect of other temporary differences*	192	
67				
68	*less*	Tax effect of amortisation of initial differences in asset values	746	
69				
70	*plus*	Deferred tax balance relating to assets acquired in the disclosure year		
71				
72	*less*	Deferred tax balance relating to assets disposed in the disclosure year	–	
73				
74	*plus*	Deferred tax cost allocation adjustment	0	
75				
76		**Closing deferred tax**		(21,603)
77				
78	**5a(vii): Disclosure of Temporary Differences**			
79		*In Schedule 14, Box 6, provide descriptions and workings of items recorded in the asterisked category in Schedule 5a(vi) (Tax effect of other temporary differences).*		
80				
81	**5a(viii): Regulatory Tax Asset Base Roll-Forward**			
82				**($000)**
83		**Opening sum of regulatory tax asset values**	160,314	
84	*less*	Tax depreciation	16,814	
85	*plus*	Regulatory tax asset value of assets commissioned	33,968	
86	*less*	Regulatory tax asset value of asset disposals	225	
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**		177,243

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For Year Ended	**31 March 2022**

SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

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

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

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

	Name of related party	Nature of opex or capex service provided	Total value of transactions ($000)
38		[Select one]	
39		[Select one]	
40		[Select one]	
41		[Select one]	
42		[Select one]	
43		[Select one]	
44		[Select one]	
45		[Select one]	
46		[Select one]	
47		[Select one]	
48		[Select one]	
49		[Select one]	
50		[Select one]	
51		[Select one]	
52		[Select one]	
53	**Total value of related party transactions**		–

54 ** include additional rows if needed*
55

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2022**

SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

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

sch ref

7

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

9

sch ref	Issuing party	Issue date	Pricing date	Original tenor (in years)	Coupon rate (%)	Book value at issue date (NZD)	Book value at date of financial statements (NZD)	Term Credit Spread Difference	Debt issue cost readjustment
11	Counties 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 2022**

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref

5d(i): Operating Cost Allocations

		Value allocated ($000s)			
	Arm's length deduction	**Electricity distribution services**	**Non-electricity distribution services**	**Total**	**OVABAA allocation increase ($000s)**
Service interruptions and emergencies					
Directly attributable		3,154			
Not directly attributable				–	
Total attributable to regulated service		3,154			
Vegetation management					
Directly attributable		1,786			
Not directly attributable				–	
Total attributable to regulated service		1,786			
Routine and corrective maintenance and inspection					
Directly attributable		1,223			
Not directly attributable				–	
Total attributable to regulated service		1,223			
Asset replacement and renewal					
Directly attributable		561			
Not directly attributable				–	
Total attributable to regulated service		561			
System operations and network support					
Directly attributable		3,705			
Not directly attributable				–	
Total attributable to regulated service		3,705			
Business support					
Directly attributable		523			
Not directly attributable		8,051	1,509	9,560	
Total attributable to regulated service		8,574			
Operating costs directly attributable		10,952			
Operating costs not directly attributable	–	8,051	1,509	9,560	–
Operational expenditure		19,003			

5d(ii): Other Cost Allocations

	($000)
Pass through and recoverable costs	
Pass through costs	
Directly attributable	944
Not directly attributable	
Total attributable to regulated service	944
Recoverable costs	
Directly attributable	11,585
Not directly attributable	
Total attributable to regulated service	11,585

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

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

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

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

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

† include additional rows if needed

Company Name	Counties Energy Limited
For Year Ended	31 March 2022

SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

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

sch ref		
7	**5e(i): Regulated Service Asset Values**	
8		**Value allocated ($000s)**
9		**Electricity distribution services**
10	**Subtransmission lines**	
11	Directly attributable	18,209
12	Not directly attributable	
13	**Total attributable to regulated service**	18,209
14	**Subtransmission cables**	
15	Directly attributable	220
16	Not directly attributable	
17	**Total attributable to regulated service**	220
18	**Zone substations**	
19	Directly attributable	60,612
20	Not directly attributable	
21	**Total attributable to regulated service**	60,612
22	**Distribution and LV lines**	
23	Directly attributable	131,284
24	Not directly attributable	
25	**Total attributable to regulated service**	131,284
26	**Distribution and LV cables**	
27	Directly attributable	51,335
28	Not directly attributable	
29	**Total attributable to regulated service**	51,335
30	**Distribution substations and transformers**	
31	Directly attributable	45,902
32	Not directly attributable	
33	**Total attributable to regulated service**	45,902
34	**Distribution switchgear**	
35	Directly attributable	24,209
36	Not directly attributable	
37	**Total attributable to regulated service**	24,209
38	**Other network assets**	
39	Directly attributable	6,228
40	Not directly attributable	
41	**Total attributable to regulated service**	6,228
42	**Non-network assets**	
43	Directly attributable	26,866
44	Not directly attributable	9,613
45	**Total attributable to regulated service**	36,479
46		
47	**Regulated service asset value directly attributable**	364,865
48	**Regulated service asset value not directly attributable**	9,613
49	**Total closing RAB value**	374,478
50		

51	**5e(ii): Changes in Asset Allocations* †**				
52				**($000)**	
53	**Change in asset value allocation 1**			**CY-1**	**Current Year (CY)**
54	Asset category		Original allocation		
55	Original allocator or line items		New allocation		
56	New allocator or line items		Difference	–	–
57					
58	Rationale for change				
59					
60					
61				**($000)**	
62	**Change in asset value allocation 2**			**CY-1**	**Current Year (CY)**
63	Asset category		Original allocation		
64	Original allocator or line items		New allocation		
65	New allocator or line items		Difference	–	–
66					
67	Rationale for change				
68					
69					
70				**($000)**	
71	**Change in asset value allocation 3**			**CY-1**	**Current Year (CY)**
72	Asset category		Original allocation		
73	Original allocator or line items		New allocation		
74	New allocator or line items		Difference	–	–
75					
76	Rationale for change				
77					
78					

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

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2022**

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

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

sch ref

sch ref			($000)	($000)
7		**6a(i): Expenditure on Assets**	**($000)**	**($000)**
8		Consumer connection		18,871
9		System growth		762
10		Asset replacement and renewal		35,522
11		Asset relocations		330
12		Reliability, safety and environment:		
13		Quality of supply	376	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	–	
16		**Total reliability, safety and environment**		376
17		**Expenditure on network assets**		55,861
18		Expenditure on non-network assets		6,070
19				
20		**Expenditure on assets**		61,931
21	*plus*	Cost of financing		177
22	*less*	Value of capital contributions		25,840
23	*plus*	Value of vested assets		–
24				
25		**Capital expenditure**		36,268

sch ref		($000)
26	**6a(ii): Subcomponents of Expenditure on Assets (where known)**	**($000)**
27	Energy efficiency and demand side management, reduction of energy losses	
28	Overhead to underground conversion	1,640
29	Research and development	

sch ref			($000)	($000)
30		**6a(iii): Consumer Connection**		
31		*Consumer types defined by EDB**	**($000)**	**($000)**
32		Urban residential	6,083	
33		Urban commercial	8,530	
34		Rural residential	3,041	
35		Rural commercial	1,217	
36				
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		18,871
39				
40	*less*	Capital contributions funding consumer connection expenditure	18,682	
41		**Consumer connection less capital contributions**		189

sch ref			System Growth ($000)	Asset Replacement and Renewal ($000)
42		**6a(iv): System Growth and Asset Replacement and Renewal**		
45		Subtransmission	10	110
46		Zone substations	615	10,711
47		Distribution and LV lines	2	9,596
48		Distribution and LV cables	–	12,264
49		Distribution substations and transformers	135	1,705
50		Distribution switchgear	–	435
51		Other network assets	–	701
52		**System growth and asset replacement and renewal expenditure**	762	35,522
53	*less*	Capital contributions funding system growth and asset replacement and renewal		7,158
54		**System growth and asset replacement and renewal less capital contributions**	762	28,364
55				

sch ref			($000)	($000)
56		**6a(v): Asset Relocations**		
57		*Project or programme**	**($000)**	**($000)**
58		Various relocation (largely reimbursed by customers)	330	
59				
60				
61				
62				
63		** include additional rows if needed*		
64		All other projects or programmes - asset relocations	–	
65		**Asset relocations expenditure**		330
66	*less*	Capital contributions funding asset relocations		
67		**Asset relocations less capital contributions**		330
68				

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2022**

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

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

sch ref				
69		**6a(vi): Quality of Supply**		
70		*Project or programme**	**($000)**	**($000)**
71		Voltage upgrades	376	
72				
73				
74				
75				
76		** include additional rows if needed*		
77		All other projects programmes - quality of supply	–	
78		**Quality of supply expenditure**		376
79	*less*	Capital contributions funding quality of supply	–	
80		**Quality of supply less capital contributions**		376
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 software	2,300	
110		Building upgrades	540	
111		Land	2,460	
112		Vehicles	154	
113		Other plant and equipment	616	
114		** include additional rows if needed*		
115		All other projects or programmes - routine expenditure		
116		**Routine expenditure**		6,070
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**		6,070

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2022**

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

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

sch ref			
7	**6b(i): Operational Expenditure**	**($000)**	**($000)**
8	Service interruptions and emergencies	3,154	
9	Vegetation management	1,786	
10	Routine and corrective maintenance and inspection	1,223	
11	Asset replacement and renewal	561	
12	**Network opex**		6,724
13	System operations and network support	3,705	
14	Business support	8,574	
15	**Non-network opex**		12,279
16			
17	**Operational expenditure**		19,003
18	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
19	Energy efficiency and demand side management, reduction of energy losses		
20	Direct billing*		
21	Research and development		
22	Insurance		524
23	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2022**

SCHEDULE 7: COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE

This schedule compares actual revenue and expenditure to the previous forecasts that were made for the disclosure year. Accordingly, this schedule requires the forecast revenue and expenditure information from previous disclosures to be inserted.

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

sch ref

sch ref		Target ($000) [1]	Actual ($000)	% variance
7	**7(i): Revenue**			
8	Line charge revenue	53,397	56,353	6%
		Forecast ($000) [2]	**Actual ($000)**	**% variance**
9	**7(ii): Expenditure on Assets**			
10	Consumer connection	8,500	18,871	122%
11	System growth	8,105	762	(91%)
12	Asset replacement and renewal	38,568	35,522	(8%)
13	Asset relocations	300	330	10%
14	Reliability, safety and environment:			
15	Quality of supply	350	376	7%
16	Legislative and regulatory	–	–	–
17	Other reliability, safety and environment	–	–	–
18	**Total reliability, safety and environment**	350	376	7%
19	**Expenditure on network assets**	55,823	55,861	0%
20	Expenditure on non-network assets	17,748	6,070	(66%)
21	Expenditure on assets	73,571	61,931	(16%)
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	2,100	3,154	50%
24	Vegetation management	2,000	1,786	(11%)
25	Routine and corrective maintenance and inspection	1,650	1,223	(26%)
26	Asset replacement and renewal	1,030	561	(46%)
27	**Network opex**	6,780	6,724	(1%)
28	System operations and network support	3,566	3,705	4%
29	Business support	8,812	8,574	(3%)
30	**Non-network opex**	12,378	12,279	(1%)
31	**Operational expenditure**	19,158	19,003	(1%)
32	**7(iv): Subcomponents of Expenditure on Assets (where known)**			
33	Energy efficiency and demand side management, reduction of energy losses	–	–	–
34	Overhead to underground conversion	300	1,640	447%
35	Research and development	–	–	–
36				
37	**7(v): Subcomponents of Operational Expenditure (where known)**			
38	Energy efficiency and demand side management, reduction of energy losses	–	–	–
39	Direct billing	–	–	–
40	Research and development	–	–	–
41	Insurance	354	524	48%
42				

43 *1 From the nominal dollar target revenue for the disclosure year disclosed under clause 2.4.3(3) of this determination*

44 *2 From the CY+1 nominal dollar expenditure forecasts disclosed in accordance with clause 2.6.6 for the forecast period starting at the beginning of the disclosure year (the second to last disclosure of Schedules 11a and 11b)*

1000

Company Name **Counties Energy Limited**
For Year Ended **31 March 2022**
ɾork / Sub-Network Name

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

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

sch ref	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)
15	Business	Commercial	Standard	7,021	114,793
16	3 Rate	Commercial	Standard	18	3,004
17	Standard Domestic	Residential	Standard	20,784	206,930
18	Low User Domestic	Residential	Standard	17,771	101,054
19	Prepaid Domestic	Residential	Standard	–	–
20	Time Of Use	Commercial	Standard	173	116,158
21	Streetlights	Commercial	Standard	9	1,787
22	Major Customer A	Commercial	Non-standard	3	42,165
23	Major Customer B	Commercial	Non-standard	2	44,545
24	Major Customer C	Commercial	Non-standard	2	14,139
25	Major Customer D	Commercial	Non-standard	2	11,461
26	*Add extra rows for additional consumer groups or price category codes as necessary*				
27			Standard consumer totals	45,776	543,726
28			Non-standard consumer totals	9	112,310
29			Total for all consumers	45,785	656,035

Billed quantities by price component

sch ref	Consumer group	00700-1100	1700-2200	2400-0700	Anytime	Day	Econo	M/W Light	Night	Off Peak	Peak	Priority Econo	Peak Saver
12/13	Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh
15	Business				107,791,700	7,001,409							
16	3 Rate									2,160,908	843,015		
17	Standard Domestic				162,519,904	44,409,923							
18	Low User Domestic				75,891,781	25,162,496							
19	Prepaid Domestic												
20	Time Of Use	24,693,733	36,772,908	26,404,759						28,286,579			
21	Streetlights							412,709					
22	Major Customer A												
23	Major Customer B												
24	Major Customer C												
25	Major Customer D												
27	Standard consumer totals	24,693,733	36,772,908	26,404,759	346,203,385	76,573,828	–	412,709	–	30,447,487	843,015	–	–
28	Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–	–	–
29	Total for all consumers	24,693,733	36,772,908	26,404,759	346,203,385	76,573,828	–	412,709	–	30,447,487	843,015	–	–

sch ref	Consumer group	Prepay	Summer Peak	Streetlight	Thrifty Night	Winter Peak	Annual Contract	Export	Demand	Reactive	Supply	Transformer
12/13	Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kVA	kVArh	Day	Month
15	Business							404,782		184,044	447,310	
16	3 Rate											
17	Standard Domestic							1,306,540			1,885,941	
18	Low User Domestic							947,280			2,139,723	
19	Prepaid Domestic											
20	Time Of Use								382,611	6,787,051		5,947
21	Streetlights			1,373,847								
22	Major Customer A						42,164,818					
23	Major Customer B						44,545,203					
24	Major Customer C						14,138,718					
25	Major Customer D						11,460,885					
27	Standard consumer totals	–	–	1,373,847	–	–	–	2,658,602	382,611	6,971,094	4,472,974	5,947
28	Non-standard consumer totals	–	–	–	–	–	112,309,624	–	–	–	–	–
29	Total for all consumers	–	–	1,373,847	–	–	112,309,624	2,658,602	382,611	6,971,094	4,472,974	5,947

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

sch ref	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)
38	Business	Commercial	Standard	$12,533	$2,417	$12,533	
39	3 Rate	Commercial	Standard	$266	$51	$266	
40	Standard Domestic	Residential	Standard	$20,843	$4,020	$20,843	
41	Low User Domestic	Residential	Standard	$10,816	$2,086	$10,816	
42	Prepaid Domestic	Residential	Standard	–	–	–	
43	Time Of Use	Commercial	Standard	$7,910	$1,526	$7,910	
44	Streetlights	Commercial	Standard	$740	$143	$740	
45	Major Customer A	Industrial	Non-standard	$1,166	$225	$1,166	
46	Major Customer B	Industrial	Non-standard	$1,058	$204	$1,058	
47	Major Customer C	Industrial	Non-standard	$482	$93	$482	
48	Major Customer D	Industrial	Non-standard	$539	$104	$539	
49	*Add extra rows for additional consumer groups or price category codes as necessary*						
50			Standard consumer totals	$53,108	$10,243	$53,108	–
51			Non-standard consumer totals	$3,245	$626	$3,245	–
52			Total for all consumers	$56,353	$10,869	$56,353	–

Line charge revenues ($000) by price component

sch ref	Consumer group	0700-1100	1700-2200	2400-0700	Anytime	Day	Econo	M/W Light	Night	Off Peak	Peak	Priority Econo	Peak Saver
35/36	Rate (eg, $ per day, $ per kWh, etc.)	0.037	0.037	0.011	0.092	0.042	0.000	0.095	0.000	0.019	0.162	0.000	0.000
38	Business	–	–	–	$9,606	$309	–	–	–	–	–	–	–
39	3 Rate	–	–	–	–	–	–	–	–	$129	$137	–	–
40	Standard Domestic	–	–	–	$13,748	$1,351	–	–	–	–	–	–	–
41	Low User Domestic	–	–	–	$8,408	$1,593	–	–	–	–	–	–	–
42	Prepaid Domestic	–	–	–	–	–	–	–	–	–	–	–	–
43	Time Of Use	$925	$1,372	$286	–	–	–	–	–	$434	–	–	–
44	Streetlights	–	–	–	–	–	–	$39	–	–	–	–	–
45	Major Customer A	–	–	–	–	–	–	–	–	–	–	–	–
46	Major Customer B	–	–	–	–	–	–	–	–	–	–	–	–
47	Major Customer C	–	–	–	–	–	–	–	–	–	–	–	–
48	Major Customer D	–	–	–	–	–	–	–	–	–	–	–	–
50	Standard consumer totals	$925	$1,372	$286	$31,763	$3,253	–	$39	–	$563	$137	–	–
51	Non-standard consumer totals	–	–	–	–	–	–	–	–	–		–	–
52	Total for all consumers	$925	$1,372	$286	$31,763	$3,253	–	$39	–	$563	$137	–	–

sch ref	Consumer group	Prepay	Summer Peak	Streetlight	Thrifty Night	Winter Peak	Annual Contract	Export	Demand	Reactive	Supply	Transformer
35/36	Rate (eg, $ per day, $ per kWh, etc.)	0.000	0.000	0.510	0.000	0.000	0.029	0.009	8.917	0.048	2.044	194.248
38	Business	–	–	–	–	–	–	$3	–	$9	$2,605	–
39	3 Rate	–	–	–	–	–	–	–	–	–	–	–
40	Standard Domestic	–	–	–	–	–	–	$11	–	–	$5,732	–
41	Low User Domestic	–	–	–	–	–	–	$8	–	–	$806	–
42	Prepaid Domestic	–	–	–	–	–	–	–	–	–	–	–
43	Time Of Use	–	–	–	–	–	–	–	$3,412	$325	–	$1,155
44	Streetlights	–	–	$701	–	–	–	–	–	–	–	–
45	Major Customer A	–	–	–	–	–	$1,166	–	–	–	–	–
46	Major Customer B	–	–	–	–	–	$1,058	–	–	–	–	–
47	Major Customer C	–	–	–	–	–	$482	–	–	–	–	–
48	Major Customer D	–	–	–	–	–	$539	–	–	–	–	–
50	Standard consumer totals	–	–	$701	–	–	–	$23	$3,412	$334	$9,143	$1,155
51	Non-standard consumer totals	–	–	–	–	–	$3,245	–	–	–	–	–
52	Total for all consumers	–	–	$701	–	–	$3,245	$23	$3,412	$334	$9,143	$1,155

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

55 Number of directly billed ICPs at year end: 9

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2022**
Network / Sub-network Name	

SCHEDULE 9a: ASSET REGISTER

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

sch ref

	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
8								
9	All	Overhead Line	Concrete poles / steel structure	No.	26,000	26,110	110	3
10	All	Overhead Line	Wood poles	No.	1,832	1,803	(29)	3
11	All	Overhead Line	Other pole types	No.	61	85	24	3
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	71	71	0	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	65	66	1	4
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	2	2	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	N/A
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	N/A
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	0	0	4
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	6	–	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	4	4	–	4
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	5	5	4
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	19	15	(4)	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	31	29	(2)	4
29	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	N/A
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	12	12	–	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	93	97	4	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	17	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1,454	1,467	13	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	242	275	33	3
39	HV	Distribution Cable	Distribution UG PILC	km	14	7	(7)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	2	2	0	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	41	40	(1)	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.	5,042	5,107	65	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.	318	357	39	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	3,180	3,195	15	3
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	951	983	32	3
48	HV	Distribution Transformer	Voltage regulators	No.	15	15	–	3
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	927	972	45	3
50	LV	LV Line	LV OH Conductor	km	713	705	(8)	3
51	LV	LV Cable	LV UG Cable	km	830	876	46	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	47	46	(1)	3
53	LV	Connections	OH/UG consumer service connections	No.	46,749	48,456	1,707	3
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	186	186	–	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	38	19	(19)	3
57	All	Load Control	Centralised plant	Lot	6	6	–	4
58	All	Load Control	Relays	No	3,217	3,217	–	3
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2022**
Network / Sub-network Name	

SCHEDULE 9b: ASSET AGE PROFILE

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

sch ref

8 **Disclosure Year (year ended)** 31 March 2020

Number of assets at disclosure year end by installation date

9	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	No. with age unknown	Items at end of year	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.	16	19	161	1,881	3,272	5,882	6,453	240	715	362	270	345	329	420	319	412	539	310	324	254	134	232	131	120	1,241	546	267	360	477	76	3	26,110	–	3
11	All	Overhead Line	Wood poles	No.	–	1	4	46	109	91	470	27	10	9	1	5	4	5	2	5	13	3	5	6	3	7	6	4	818	142	3	–	2	1	1	1,803	–	3
12	All	Overhead Line	Other pole types	No.	–	–	5	15	12	2	1	–	–	–	–	–	–	–	1	–	–	–	–	–	–	4	–	–	23	–	–	6	5	–	11	85	–	3
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	3	–	–	16	30	7	–	–	–	–	–	14	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	71	–	4
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	3	–	–	–	–	–	18	–	6	–	–	–	–	20	–	–	–	–	–	–	–	10	5	–	–	–	2	–	–	–	–	66	–	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	–	0	–	–	–	–	–	0	0	–	0	–	–	–	0	–	–	–	–	–	–	–	0	0	0	–	–	2	–	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	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	4	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	6	–	4
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	–	1	–	–	–	–	–	–	1	–	–	–	–	–	–	–	1	–	–	–	–	1	–	–	–	–	4	–	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.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	13	10	–	1	2	–	–	–	–	–	2	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	29	–	4
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	–	–	2	–	–	–	–	2	1	–	–	–	–	–	–	–	4	–	–	–	–	2	–	–	1	–	–	–	12	–	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	6	–	–	–	11	–	–	–	–	–	–	–	8	–	–	–	–	29	–	17	–	–	–	–	26	–	–	–	–	97	–	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	–	–	–	17	–	4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	27	43	73	217	208	291	265	19	19	29	17	9	12	25	13	9	28	18	13	10	8	7	7	9	14	32	4	20	19	1	–	1,467	–	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	–	–	–	–	–	1	24	4	5	2	2	7	8	15	10	2	9	12	8	9	9	16	15	9	11	12	23	27	31	1	2	275	–	3
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	–	–	2	5	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7	–	3
41	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	0	0	–	–	2	–	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionaliser:	No.	–	–	–	–	–	2	3	2	1	–	–	–	3	–	3	1	–	1	–	–	8	2	–	–	1	7	2	3	1	–	–	40	–	3
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	–	1	18	60	177	451	1,088	200	161	104	112	99	141	58	130	83	101	231	234	197	262	164	160	141	132	200	135	72	106	30	59	5,107	–	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	15	4	6	7	10	31	33	49	70	44	2	5	357	–	3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	–	15	26	92	248	529	63	92	62	83	81	91	43	89	38	50	174	200	164	228	133	137	107	78	133	87	46	68	27	11	3,195	–	3
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	–	2	3	16	130	27	20	19	25	21	26	28	24	31	18	38	46	29	61	48	42	41	60	59	56	41	59	9	4	983	–	3
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–	–	–	1	1	–	–	–	8	3	–	–	–	15	–	3
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	6	5	13	128	27	20	19	25	21	27	29	24	31	18	37	46	28	61	50	42	39	58	55	54	38	57	9	5	972	–	3
51	LV	LV Line	LV OH Conductor	km	–	–	1	2	4	3	637	7	5	6	3	2	4	2	1	3	4	1	4	1	2	2	1	1	1	2	2	–	4	–	2	704	–	3
52	LV	LV Cable	LV UG Cable	km	–	–	1	1	9	4	222	24	21	22	16	16	35	43	23	16	8	20	14	30	23	44	33	40	42	47	35	37	29	4	17	876	–	3
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	–	–	–	–	–	–	2	–	–	1	1	1	–	1	1	1	2	8	5	5	6	6	–	2	1	2	2	–	–	46	–	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	89	48,456	–	3
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	5	14	4	18	2	–	–	–	2	–	–	16	–	–	–	–	4	2	–	17	38	–	12	–	26	26	–	–	–	186	–	4
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	–	–	–	–	–	–	16	–	–	–	–	–	–	2	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	19	–	3
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	2	1	–	–	–	–	–	–	1	–	–	–	–	–	–	–	1	–	–	–	–	–	1	–	–	–	6	–	4
59	All	Load Control	Relays	No	–	–	–	–	–	–	121	329	171	148	116	89	5	–	1	3	1	7	3	2	74	1125	973	37	1	2	3	6	–	–	–	3,217	–	3
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–				–	–	–	N/A

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2022**
Network / Sub-network Name	

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref				
9				
10	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**
11	> 66kV	66	0	66
12	50kV & 66kV			–
13	33kV	71	2	73
14	SWER (all SWER voltages)			–
15	22kV (other than SWER)	575	224	799
16	6.6kV to 11kV (inclusive—other than SWER)	893	88	981
17	Low voltage (< 1kV)	705	876	1,581
18	**Total circuit length (for supply)**	2,310	1,190	3,500
19				
20	Dedicated street lighting circuit length (km)	0	46	46
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			2
22				

sch ref			
23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**
24	Urban	176	8%
25	Rural	2,071	90%
26	Remote only		–
27	Rugged only	63	3%
28	Remote and rugged		–
29	Unallocated overhead lines		–
30	**Total overhead length**	2,310	100%
31			
32		**Circuit length (km)**	**(% of total circuit length)**
33	Length of circuit within 10km of coastline or geothermal areas (where known)	1,559	45%
34		**Circuit length (km)**	**(% of total overhead length)**
35	Overhead circuit requiring vegetation management	2,310	100%

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2022**

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

sch ref	Location *	Number of ICPs served	Line charge revenue ($000)
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 2022**
Network / Sub-network Name	

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref				
8	**9e(i): Consumer Connections**			
9	*Number of ICPs connected in year by consumer type*			
10	*Consumer types defined by EDB**		**Number of connections (ICPs)**	
11	Urban Residential		519	
12	Urban Commercial		203	
13	Rural Residential		459	
14	Rural Commercial		274	
15				
16	** include additional rows if needed*			
17	**Connections total**		1,455	
18				
19	**Distributed generation**			
20	Number of connections made in year		247	**connections**
21	Capacity of distributed generation installed in year		1.47	**MVA**
22	**9e(ii): System Demand**			
23				
24				
25	**Maximum coincident system demand**		**Demand at time of maximum coincident demand (MW)**	
26		GXP demand	120	
27	*plus*	Distributed generation output at HV and above	9	
28	**Maximum coincident system demand**		129	
29	*less*	Net transfers to (from) other EDBs at HV and above	–	
30	**Demand on system for supply to consumers' connection points**		129	
31	**Electricity volumes carried**		**Energy (GWh)**	
32		Electricity supplied from GXPs	641	
33	*less*	Electricity exports to GXPs	–	
34	*plus*	Electricity supplied from distributed generation	48	
35	*less*	Net electricity supplied to (from) other EDBs	–	
36	**Electricity entering system for supply to consumers' connection points**		690	
37	*less*	Total energy delivered to ICPs	656	
38	**Electricity losses (loss ratio)**		34	4.9%
39				
40	**Load factor**		0.61	
41	**9e(iii): Transformer Capacity**			
42			**(MVA)**	
43		Distribution transformer capacity (EDB owned)	695	
44		Distribution transformer capacity (Non-EDB owned, estimated)	74	
45	**Total distribution transformer capacity**		769	
46				
47	**Zone substation transformer capacity**		472	

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2022**
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref			
8	**10(i): Interruptions**		
9	**Interruptions by class**	**Number of interruptions**	
10	Class A (planned interruptions by Transpower)		
11	Class B (planned interruptions on the network)	248	
12	Class C (unplanned interruptions on the network)	491	
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)	85	
19	**Total**	824	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	290	201
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)		
26	Class B (planned interruptions on the network)	0.47	150.11
27	Class C (unplanned interruptions on the network)	3.46	272.78
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)	0.08	10.18
34	**Total**	4.01	433.07
35			
36	**Normalised SAIFI and SAIDI**	**Normalised SAIFI**	**Normalised SAIDI**
37	Classes B & C (interruptions on the network)	3.93	356.95
38			
39	**10(ii): Class C Interruptions and Duration by Cause**		
40			
41	**Cause**	**SAIFI**	**SAIDI**
42	Lightning	0.01	0.46
43	Vegetation	1.17	135.79
44	Adverse weather		
45	Adverse environment		
46	Third party interference	0.24	22.68
47	Wildlife	0.43	13.10
48	Human error	0.08	2.05
49	Defective equipment	0.69	70.99
50	Cause unknown	0.84	27.72
51			
52	**10(iii): Class B Interruptions and Duration by Main Equipment Involved**		
53			
54	**Main equipment involved**	**SAIFI**	**SAIDI**
55	Subtransmission lines	0.00	0.00
56	Subtransmission cables	0.00	0.00
57	Subtransmission other	0.00	0.00
58	Distribution lines (excluding LV)	0.34	118.29
69	Distribution cables (excluding LV)	0.07	13.75
60	Distribution other (excluding LV)	0.07	18.06

Company Name	**Counties Energy Limited**
For Year Ended	**31 March 2022**
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

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

62

		SAIFI	SAIDI
63	**Main equipment involved**		
64	Subtransmission lines	0.44	29.75
65	Subtransmission cables		
66	Subtransmission other	0.10	1.78
67	Distribution lines (excluding LV)	2.58	217.10
68	Distribution cables (excluding LV)	0.17	8.06
69	Distribution other (excluding LV)	0.17	16.09

70 ### 10(v): Fault Rate

		Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
71	**Main equipment involved**			
72	Subtransmission lines	19	137	13.87
73	Subtransmission cables		2	–
74	Subtransmission other	2		
75	Distribution lines (excluding LV)	433	1,468	29.50
76	Distribution cables (excluding LV)	9	312	2.88
77	Distribution other (excluding LV)	48		
78	**Total**	511		

Company Name	Counties Energy Limited
For Year Ended	31 March 2022

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 increased from 3.69% in FY21 to 9.62% in FY22 with the following items of note:

- Revenue increased by 11.2% in FY22 to $56.4m (FY21 - $50.7m);
- Operational costs decreased from 35% of lines revenue in FY21 to 34% of lines revenue with the higher revenue;
- Revaluations increased from $4.4m in FY21 to $22.8m in FY22. This was attributable to the significantly higher CPI of 6.9% (FY21 – 1.5%); and
- Commissioned assets in FY22 were $34.0m (FY21 - $49.1m).

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 $22.8m reflecting the much higher CPI of 6.9% in FY22. Commissioned assets in FY22 were $34.0m (FY21 - $49.1m). Assets being disposed of comprise non-system vehicles and minor plant and equipment ($119k) and transformers sold as scrap ($106k). A loss of $138k was recorded for these disposals. Higher depreciation in FY22 reflects network growth and investment in IT related assets to support the network in FY21.

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 ($13k), entertainment expense ($10k) and other ($3k). 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 ($684k @28% = $192k).

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 was in line with target. 7(ii): Variances above 10% listed by category: •Consumer connection was 122% above target due to a higher number of residential and large commercial connections; •System growth was 91% below target due largely to deferral of land procurement and design for future substations into FY23 ($5.3m), and the deferral of a 22kV conversion project into FY23 ($2.2m); and •Expenditure on non-network assets was lower than forecast due to a delayed start for the Glasgow site upgrade and timing of IT projects. 7(iii): Variances above 10% listed by category: • Service interruptions and emergencies were 50% above target. This is a combination of several factors such as a minor volume shift of jobs to outside of core hours, additional resources required for both safety and training reasons, and a minor increase overall in work volume; •Vegetation management was 11% below target due to resourcing and Covid restrictions; •Routine and corrective maintenance was 26% below target because of reduced delivery levels relating to Covid restrictions; and •Asset replacement and renewal was 46% below target with higher capitalisation of works through the year. 7(iv): Where justified by public safety and reliability, OHUG conversions are undertaken with the above target spend reflecting this. 7(v): Insurance increased 5% from the previous year and was in line with target which should have noted 534 rather than 354 in the AMP.

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 above target due as new connections continued at a high pace and with the mix of revenue that came through with Covid restrictions (higher numbers of consumers working from home).

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

Event recording systems were updated to include outages impacting single transformers, which previously were interpreted as LV interruptions and excluded from class C disclosure. This represents an additional 147 interruptions, 0.02 SAIFI and 4.03 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 130 faults, 0.03 SAIFI and 5.99 SAIDI. If these faults originating on LV Networks were excluded, the Distribution Lines fault rate would be 21.66 and the Distribution Cables fault rate 1.60.

Unplanned (class C) outages, as measured by SAIFI and SAIDI, returned an unfavourable result for FY22. Weather related events are having an increasing impact on reliability and impacting on other categories and in particular vegetation.

Consistent with FY21, Counties Energy has reallocated SAIFI / SAIDI arising from events initiating from privately owned network assets to Class I (0.07 SAIFI / 5.94 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 2022

Schedule 14a Mandatory Explanatory Notes on Forecast Information

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

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

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

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

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

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts
The difference between nominal and constant prices reflects inflation of 2% per annum.

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

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

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts
The difference between nominal and constant prices reflects inflation of 2% per annum.

Company Name	Counties Energy Limited
For Year Ended	31 March 2022

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 FY22, 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 disclosure for FY21, 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 FY22 would increase by 10.65% from 3.46 to 3.83 and normalised Class B and C (planned and unplanned) SAIFI by 9.37% from 3.93 to 4.30.

Counties Energy

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, 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
15 August 2022	15 August 2022

(1) The Directors of Counties Energy Limited note the amendment to the ID Determination issued by the Commerce Commission on 17 May 2021 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.

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 2022 as required by The Electricity Distribution Information Disclosure Determination 2012 (consolidated 9 December 2021).

Counties Energy Limited (the Company) is required to disclose certain information under the Electricity Distribution Information Disclosure Determination 2012 (consolidated 9 December 2021) (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 2022 (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 17 May 2021 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.

In our opinion

In our opinion, 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 opinion

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 all the information and explanations that we required to provide a basis for our 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 included the following: **Assets commissioned** ● We reconciled the assets commissioned, as per the regulatory fixed asset register, to the asset additions disclosed in the audited annual financial statements and investigated any reconciling items; ● We inspected the assets commissioned during the period, as per the regulatory fixed 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 tested a sample of assets commissioned during the disclosure period for appropriate asset category classification; **Depreciation** ● We compared the standard asset lives by asset category to those set out in the IM Determination; ● For assets with no standard asset lives we assessed the reasonableness of the lives used by reference to the accounting depreciation rates; ● We compared the spreadsheet formula utilised to calculate regulatory depreciation expense with IM Determination clause 2.2.5;

Key Assurance Matter	How our procedures addressed the key assurance matter
	Revaluation ● We recalculated the revaluation rate set out in the Input Methodologies using the relevant Consumer Price Index indices taken from the Statistics New Zealand website; ● We tested the mathematical accuracy of the revaluation calculation performed by management; and **Disposals** ● We inspected the asset disposals within the accounting fixed asset register to ensure disposals in the RAB meet the definition of a disposal per the IM Determination.
Cost and Asset Allocation The Determination relates to information concerning the supply of electricity distribution services. In addition to the regulated support of electricity, Counties Energy Limited also supplies customers with other unregulated services such as contracting Costs and asset values that relate to electricity distribution services regulated under the ID Determination should comprise: ● all of the costs directly attributable to the regulated goods or services; and ● an allocated portion of the costs that are not directly attributable. The 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 have 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 against supporting documentation to ensure their classification as either directly attributable or not directly attributable costs are appropriate and in line with the Determination; ● Inspecting the fixed asset register to identify any asset classes which based on their nature and our understanding of the business could be considered asset directly attributable to a specific business unit; ● Testing a sample of assets commissioned to supporting documentation to ensure their classification as either directly attributable or not directly attributable are appropriate and in line with the Determination;

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 allocated 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** ● Understanding why causal relationships could not be identified in allocating costs or assets and ensuring appropriate disclosure has been included outlining these in Schedule 14; ● Considering the appropriateness of the cost and asset proxy allocators used in applying the ABAA to not directly attributable costs; and ● Recalculating the split between not directly attributable costs and asset values allocated to electricity distribution services and non-electricity distribution services.
SAIDI and SAIFI Reliability Measures SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index) as disclosed in Schedule 10 are non-financial network reliability measures. These are considered key measures when assessing the performance of the network against the annual targets set. Due to the nature of the unplanned interruptions there are inherent limitations in capturing complete and accurate data for all interruptions. The calculations of the disclosed information are also complex and require careful consideration. Due to the importance of the SAIDI and SAIFI measures within the Disclosure Information, inherent limitations in capturing unplanned interruption data and complexities within the regulations, we have considered the reliability measures to be a key area of focus.	We obtained an understanding of the Company's control environment and processes around capturing, recording and reviewing interruption data. Our procedures over the non-financial network reliability measures included: ● testing a sample of planned and unplanned outages from the interruptions output to supporting documentation including internally generated work orders and SCADA reports to test the duration & cause of the interruption ensuring appropriate classification within the Information Disclosure schedules; ● recalculated a sample of the outage minutes that are calculated by the outage management system; ● assessed completeness of the interruption information by performing a media search for significant events that should result in an interruption being recorded, performing a sequential number check on the interruption information and detailed testing of call records and the GIS database; and ● re-performed the normalisation calculation used in calculating reported SAIDI and SAIFI in the Information Disclosure schedules.

Directors' responsibilities

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

- the **preparation of the Disclosure Information; and**
- **the Rel**ated 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 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 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, the assurance engagement on the Default Price-Quality Path 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
Hamilton, New Zealand
On behalf of the Auditor-General
15 August 2022

PricewaterhouseCoopers