



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

For the Year Ended 31 March 2021

Contents

1. Current Year Schedules

Sch.No.	Description
1	Analytical Ratios
2	Report on Return on Investment
3	Report on Regulatory Profit
4	Report on Value of the Regulatory Asset Base (Rolled Forward)
5a	Report on Regulatory Tax Allowance
5b	Report on Related Party Transactions
5c	Report on Term Credit Spread Differential Allowance
5d	Report on Cost Allocations
5e	Report on Asset Allocations
6a	Report on Capital Expenditure for the Disclosure Year
6b	Report on Operational Expenditure for the Disclosure Year
7	Comparison of Forecasts to Actual Expenditure
8	Report on Billed Quantities and Line Charge Revenues (by Price Component)
9a	Asset Register
9b	Asset Age Profile
9c	Report on Overhead Lines and Underground Cables
9d	Report on Embedded Networks
9e	Report on Network Demand
10	Report on Network Reliability
14	Mandatory Explanatory Notes
15	Voluntary Explanatory Notes

Directors Certificate

18	Certification for Year-end Disclosures
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2. Auditors Opinion

Company Name **Counties Energy Limited**
For Year Ended **31 March 2021**

SCHEDULE 1: ANALYTICAL RATIOS

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

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

sch ref

1(i): Expenditure metrics

	Expenditure per GWh energy delivered to ICPs (\$/GWh)	Expenditure per average no. of ICPs (\$/ICP)	Expenditure per MW maximum coincident system demand (\$/MW)	Expenditure per km circuit length (\$/km)	Expenditure per MVA of capacity from EDB-owned distribution transformers (\$/MVA)
Operational expenditure					
Network	27,925	399	125,922	5,181	36,884
Non-network	10,126	145	45,660	1,879	13,374
	17,799	254	80,262	3,302	23,509
Expenditure on assets					
Network	75,455	1,078	340,248	13,999	99,661
Non-network	69,717	996	314,376	12,935	92,083
	5,738	82	25,872	1,064	7,578

1(ii): Revenue metrics

	Revenue per GWh energy delivered to ICPs (\$/GWh)	Revenue per average no. of ICPs (\$/ICP)
Total consumer line charge revenue		
Standard consumer line charge revenue	79,710	1,139
Non-standard consumer line charge revenue	91,617	1,075
	24,839	312,882

1(iii): Service intensity measures

Demand density	41	Maximum coincident system demand per km of circuit length (for supply) (kW/km)
Volume density	186	Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)
Connection point density	13	Average number of ICPs per km of circuit length (for supply) (ICPs/km)
Energy intensity	14,283	Total energy delivered to ICPs per average number of ICPs (kWh/ICP)

1(iv): Composition of regulatory income

	(\$000)	% of revenue
Operational expenditure	17,755	34.97%
Pass-through and recoverable costs excluding financial incentives and wash-ups	12,114	23.86%
Total depreciation	10,565	20.81%
Total revaluations	4,364	8.59%
Regulatory tax allowance	3,079	6.06%
Regulatory profit/(loss) including financial incentives and wash-ups	11,626	22.90%
Total regulatory income	50,776	

1(v): Reliability

Interruption rate	16.08	Interruptions per 100 circuit km
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Company Name

Counties Energy Limited

For Year Ended

31 March 2021

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**ROI – comparable to a post tax WACC**

Reflecting all revenue earned
Excluding revenue earned from financial incentives
Excluding revenue earned from financial incentives and wash-ups

CY-2 31 Mar 19 %	CY-1 31 Mar 20 %	Current Year CY 31 Mar 21 %
6.35%	5.88%	3.69%
6.35%	5.88%	3.69%
6.35%	5.88%	3.69%

Mid-point estimate of post tax WACC

25th percentile estimate
75th percentile estimate

4.75%	4.27%	3.72%
4.07%	3.59%	3.04%
5.43%	4.95%	4.40%

ROI – comparable to a vanilla WACC

Reflecting all revenue earned
Excluding revenue earned from financial incentives
Excluding revenue earned from financial incentives and wash-ups

6.86%	6.31%	4.02%
6.86%	6.31%	4.02%
6.86%	6.31%	4.02%

WACC rate used to set regulatory price path

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Mid-point estimate of vanilla WACC

25th percentile estimate
75th percentile estimate

5.26%	4.69%	4.05%
4.58%	4.01%	3.37%
5.94%	5.37%	4.73%

2(ii): Information Supporting the ROI

(\$000)

Total opening RAB value
plus Opening deferred tax
Opening RIV

Line charge revenue

Expenses cash outflow
add Assets commissioned
less Asset disposals
add Tax payments
less Other regulated income
Mid-year net cash outflows

Term credit spread differential allowance

Total closing RAB value
less Adjustment resulting from asset allocation
less Lost and found assets adjustment
plus Closing deferred tax
Closing RIV

287,274	
(17,408)	
	269,866
	50,681
29,869	
49,142	
179	
1,108	
95	
	79,846
	–
330,036	
0	
–	
(19,379)	
	310,657

ROI – comparable to a vanilla WACC

4.02%

Leverage (%)

42%

Cost of debt assumption (%)

2.82%

Corporate tax rate (%)

28%

ROI – comparable to a post tax WACC

3.69%

Company Name

Counties Energy Limited

For Year Ended

31 March 2021

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

3.95%

Year-end ROI – comparable to a post tax WACC

3.62%

* 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 2021**

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	50,681
10	plus Gains / (losses) on asset disposals	(87)
11	plus Other regulated income (other than gains / (losses) on asset disposals)	182
12		
13	Total regulatory income	50,776
14	Expenses	
15	less Operational expenditure	17,755
16		
17	less Pass-through and recoverable costs excluding financial incentives and wash-ups	12,114
18		
19	Operating surplus / (deficit)	20,907
20		
21	less Total depreciation	10,565
22		
23	plus Total revaluations	4,364
24		
25	Regulatory profit / (loss) before tax	14,705
26		
27	less Term credit spread differential allowance	—
28		
29	less Regulatory tax allowance	3,079
30		
31	Regulatory profit/(loss) including financial incentives and wash-ups	11,626
32		
33	3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups	(\$000)
34	Pass through costs	
35	Rates	700
36	Commerce Act levies	91
37	Industry levies	133
38	CPP specified pass through costs	
39	Recoverable costs excluding financial incentives and wash-ups	
40	Electricity lines service charge payable to Transpower	10,714
41	Transpower new investment contract charges	201
42	System operator services	
43	Distributed generation allowance	275
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	12,114
47		

Company Name **Counties Energy Limited**
 For Year Ended **31 March 2021**

SCHEDULE 3: REPORT ON REGULATORY PROFIT

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sch ref

3(iii): Incremental Rolling Incentive Scheme

(\$000)

CY-1 CY
 31 Mar 20 31 Mar 21

Allowed controllable opex

Actual controllable opex

Incremental change in year

Previous years' incremental change Previous years' incremental change adjusted for inflation

CY-5 31 Mar 16

CY-4 31 Mar 17

CY-3 31 Mar 18

CY-2 31 Mar 19

CY-1 31 Mar 20

Net incremental rolling incentive scheme

Net recoverable costs allowed under incremental rolling incentive scheme

3(iv): Merger and Acquisition Expenditure

(\$000)

Merger and acquisition expenditure

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)

3(v): Other Disclosures

(\$000)

Self-insurance allowance

Company Name	Counties Energy Limited
For Year Ended	31 March 2021

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)

for year ended

	RAB 31 Mar 17 (\$000)	RAB 31 Mar 18 (\$000)	RAB 31 Mar 19 (\$000)	RAB 31 Mar 20 (\$000)	RAB 31 Mar 21 (\$000)
Total opening RAB value	231,077	241,528	253,205	270,478	287,274
less Total depreciation	7,690	7,899	8,228	9,353	10,565
plus Total revaluations	4,997	2,661	3,754	6,847	4,364
plus Assets commissioned	13,336	16,432	22,431	19,344	49,142
less Asset disposals	193	108	92	42	179
plus Lost and found assets adjustment					—
plus Adjustment resulting from asset allocation		593	(592)		0
Total closing RAB value	241,528	253,205	270,478	287,274	330,036

4(ii): Unallocated Regulatory Asset Base

	Unallocated RAB * (\$000)	RAB (\$000)
Total opening RAB value	288,234	287,274
less Total depreciation	10,607	10,565
plus Total revaluations	4,374	4,364
plus Assets commissioned (other than below)	49,509	49,142
Assets acquired from a regulated supplier	—	—
Assets acquired from a related party	—	—
Assets commissioned	49,509	49,142
less Asset disposals (other than below)	182	179
Asset disposals to a regulated supplier	—	—
Asset disposals to a related party	—	—
Asset disposals	182	179
plus Lost and found assets adjustment		
plus Adjustment resulting from asset allocation		0
Total closing RAB value	331,328	330,036

* 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 _t	1.068
CPI _{t-4}	1.052
Revaluation rate (%)	1.52%

	Unallocated RAB *		RAB
	(\$'000)	(\$'000)	(\$'000)
Total opening RAB value	288,234		287,274
less Opening value of fully depreciated, disposed and lost assets	616		366
Total opening RAB value subject to revaluation	287,618		286,908
Total revaluations		4,374	4,364

4(iv): Roll Forward of Works Under Construction

	Unallocated works under construction	Allocated works under construction
Works under construction—preceding disclosure year	31,474	31,474
plus Capital expenditure	36,910	36,543
less Assets commissioned	49,509	49,142
plus Adjustment resulting from asset allocation		
Works under construction - current disclosure year	18,875	18,875
Highest rate of capitalised finance applied		2.57%

Company Name	Counties Energy Limited
For Year Ended	31 March 2021

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(v): Regulatory Depreciation

Depreciation - standard
 Depreciation - no standard life assets
 Depreciation - modified life assets
 Depreciation - alternative depreciation in accordance with CPP
Total depreciation

Unallocated RAB *		RAB
(\$000)	(\$000)	(\$000)
8,587		8,587
2,020		1,978
	10,607	10,565

4(vi): Disclosure of Changes to Depreciation Profiles

(\$000 unless otherwise specified)

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

* include additional rows if needed

4(vii): Disclosure by Asset Category

(\$000 unless otherwise specified)

	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
Total opening RAB value	17,134	218	23,784	105,724	46,730	42,876	16,147	5,643	29,018	287,274
less Total depreciation	458	8	725	2,875	1,553	1,603	791	510	2,042	10,565
plus Total revaluations	261	3	362	1,608	711	650	245	86	438	4,364
plus Assets commissioned	217	—	26,959	11,743	2,656	686	2,801	432	3,648	49,142
less Asset disposals	—	—	—	—	—	117	—	—	62	179
plus Lost and found assets adjustment	—	—	—	—	—	—	—	—	—	—
plus Adjustment resulting from asset allocation	—	—	—	—	—	—	—	—	—	—
plus Asset category transfers	—	—	—	—	—	—	—	—	—	—
Total closing RAB value	17,154	213	50,380	116,200	48,544	42,492	18,402	5,651	31,000	330,036
Asset Life										
Weighted average remaining asset life	44.3	24.4	89.4	52.9	40.5	33.5	39.6	8.5	13.1	(years)
Weighted average expected total asset life	59.2	43.5	45.0	60.0	55.1	45.0	35.0	13.2	16.8	(years)

Company Name **Counties Energy Limited**
 For Year Ended **31 March 2021**

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

sch ref

5a(i): Regulatory Tax Allowance

(\$000)

Regulatory profit / (loss) before tax

14,705

plus Income not included in regulatory profit / (loss) before tax but taxable
 Expenditure or loss in regulatory profit / (loss) before tax but not deductible
 Amortisation of initial differences in asset values
 Amortisation of revaluations

*
 54 *
 2,663
 1,090

3,807

less Total revaluations
 Income included in regulatory profit / (loss) before tax but not taxable
 Discretionary discounts and customer rebates
 Expenditure or loss deductible but not in regulatory profit / (loss) before tax
 Notional deductible interest

4,364
 *
 *
 3,152

7,516

Regulatory taxable income

10,996

less Utilised tax losses
 Regulatory net taxable income

10,996

Corporate tax rate (%)

28%

Regulatory tax allowance

3,079

* Workings to be provided in Schedule 14

5a(ii): Disclosure of Permanent Differences

In Schedule 14, Box 5, provide descriptions and workings of items recorded in the asterisked categories in Schedule 5a(i).

5a(iii): Amortisation of Initial Difference in Asset Values

(\$000)

Opening unamortised initial differences in asset values
 less Amortisation of initial differences in asset values
 plus Adjustment for unamortised initial differences in assets acquired
 less Adjustment for unamortised initial differences in assets disposed
 Closing unamortised initial differences in asset values

69,240
 2,663
 1
 66,576

Opening weighted average remaining useful life of relevant assets (years)

26

Company Name **Counties Energy Limited**
 For Year Ended **31 March 2021**

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

sch ref

44	5a(iv): Amortisation of Revaluations			(\$000)
45				
46	Opening sum of RAB values without revaluations	257,180		
47				
48	Adjusted depreciation	9,475		
49	Total depreciation	10,565		
50	Amortisation of revaluations		1,090	
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	(17,408)		
61				
62	plus Tax effect of adjusted depreciation	2,653		
63				
64	less Tax effect of tax depreciation	4,035		
65				
66	plus Tax effect of other temporary differences*	156		
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			(19,379)
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			(\$000)
82				
83	Opening sum of regulatory tax asset values	125,760		
84	less Tax depreciation	14,409		
85	plus Regulatory tax asset value of assets commissioned	49,142		
86	less Regulatory tax asset value of asset disposals	179		
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			160,314

Company Name **Counties Energy Limited**
For Year Ended **31 March 2021**

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

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

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
Counties Energy Limited does not have any qualifying debt								
* include additional rows if needed						—	—	—

5c(ii): Attribution of Term Credit Spread Differential

Gross term credit spread differential		—
Total book value of interest bearing debt		
Leverage	42%	
Average opening and closing RAB values		
Attribution Rate (%)		—
Term credit spread differential allowance		—

Company Name **Counties Energy Limited**
For Year Ended **31 March 2021**

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref

5d(i): Operating Cost Allocations

	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase (\$000s)
Service interruptions and emergencies					
Directly attributable		2,492			
Not directly attributable				–	
Total attributable to regulated service		2,492			
Vegetation management					
Directly attributable		1,874			
Not directly attributable				–	
Total attributable to regulated service		1,874			
Routine and corrective maintenance and inspection					
Directly attributable		1,564			
Not directly attributable				–	
Total attributable to regulated service		1,564			
Asset replacement and renewal					
Directly attributable		508			
Not directly attributable				–	
Total attributable to regulated service		508			
System operations and network support					
Directly attributable		3,498			
Not directly attributable				–	
Total attributable to regulated service		3,498			
Business support					
Directly attributable		497			
Not directly attributable		7,322	1,247	8,569	
Total attributable to regulated service		7,819			
Operating costs directly attributable		10,433			
Operating costs not directly attributable	–	7,322	1,247	8,569	–
Operational expenditure		17,755			

5d(ii): Other Cost Allocations

Pass through and recoverable costs	(\$000)
Pass through costs	
Directly attributable	924
Not directly attributable	
Total attributable to regulated service	924
Recoverable costs	
Directly attributable	10,989
Not directly attributable	
Total attributable to regulated service	10,989

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

			(\$000)	
			CY-1	Current Year (CY)
Change in cost allocation 1				
Cost category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	–	–
Rationale for change				
Change in cost allocation 2				
Cost category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	–	–
Rationale for change				
Change in cost allocation 3				
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 2021

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

	Value allocated (\$000s) Electricity distribution services
Subtransmission lines	
Directly attributable	17,154
Not directly attributable	
Total attributable to regulated service	17,154
Subtransmission cables	
Directly attributable	213
Not directly attributable	
Total attributable to regulated service	213
Zone substations	
Directly attributable	50,380
Not directly attributable	
Total attributable to regulated service	50,380
Distribution and LV lines	
Directly attributable	116,200
Not directly attributable	
Total attributable to regulated service	116,200
Distribution and LV cables	
Directly attributable	48,544
Not directly attributable	
Total attributable to regulated service	48,544
Distribution substations and transformers	
Directly attributable	42,492
Not directly attributable	
Total attributable to regulated service	42,492
Distribution switchgear	
Directly attributable	18,402
Not directly attributable	
Total attributable to regulated service	18,402
Other network assets	
Directly attributable	5,651
Not directly attributable	
Total attributable to regulated service	5,651
Non-network assets	
Directly attributable	23,078
Not directly attributable	7,922
Total attributable to regulated service	31,000
Regulated service asset value directly attributable	322,114
Regulated service asset value not directly attributable	7,922
Total closing RAB value	330,036

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

			(\$000)	
			CY-1	Current Year (CY)
Change in asset value allocation 1				
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	–	–
Rationale for change				
Change in asset value allocation 2				
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	–	–
Rationale for change				
Change in asset value allocation 3				
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	–	–
Rationale for change				

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

† include additional rows if needed

Company Name **Counties Energy Limited**
For Year Ended **31 March 2021**

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

6a(i): Expenditure on Assets

	(\$000)	(\$000)
Consumer connection		10,241
System growth		5,363
Asset replacement and renewal		28,231
Asset relocations		396
Reliability, safety and environment:		
Quality of supply	96	
Legislative and regulatory	–	
Other reliability, safety and environment	–	
Total reliability, safety and environment		96
Expenditure on network assets		44,327
Expenditure on non-network assets		3,648
Expenditure on assets		47,975
plus Cost of financing		300
less Value of capital contributions		11,732
plus Value of vested assets		
Capital expenditure		36,543

6a(ii): Subcomponents of Expenditure on Assets (where known)

	(\$000)
Energy efficiency and demand side management, reduction of energy losses	
Overhead to underground conversion	6,949
Research and development	

6a(iii): Consumer Connection

Consumer types defined by EDB*	(\$000)	(\$000)
Urban residential	5,120	
Urban commercial	1,536	
Rural residential	2,560	
Rural commercial	1,025	
<i>* include additional rows if needed</i>		
Consumer connection expenditure		10,241
less Capital contributions funding consumer connection expenditure	10,241	
Consumer connection less capital contributions		–

6a(iv): System Growth and Asset Replacement and Renewal

	System Growth (\$000)	Asset Replacement and Renewal (\$000)
Subtransmission	28	198
Zone substations	3,759	5,541
Distribution and LV lines	788	9,157
Distribution and LV cables	762	5,976
Distribution substations and transformers	26	556
Distribution switchgear	–	6,352
Other network assets	–	451
System growth and asset replacement and renewal expenditure	5,363	28,231
less Capital contributions funding system growth and asset replacement and renewal	666	593
System growth and asset replacement and renewal less capital contributions	4,697	27,638

6a(v): Asset Relocations

Project or programme*	(\$000)	(\$000)
Various relocation (largely reimbursed by customers)	396	
<i>* include additional rows if needed</i>		
All other projects or programmes - asset relocations	–	
Asset relocations expenditure		396
less Capital contributions funding asset relocations	232	
Asset relocations less capital contributions		164

Company Name

Counties Energy Limited

For Year Ended

31 March 2021

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

6a(vi): Quality of Supply

Project or programme*

Voltage upgrades

(\$000)

(\$000)

96

* include additional rows if needed

All other projects programmes - quality of supply

Quality of supply expenditure

96

less Capital contributions funding quality of supply

Quality of supply less capital contributions

96

6a(vii): Legislative and Regulatory

Project or programme*

Nil

(\$000)

(\$000)

* include additional rows if needed

All other projects or programmes - legislative and regulatory

Legislative and regulatory expenditure

-

less Capital contributions funding legislative and regulatory

Legislative and regulatory less capital contributions

-

6a(viii): Other Reliability, Safety and Environment

Project or programme*

Nil

(\$000)

(\$000)

* include additional rows if needed

All other projects or programmes - other reliability, safety and environment

Other reliability, safety and environment expenditure

-

less Capital contributions funding other reliability, safety and environment

Other reliability, safety and environment less capital contributions

-

6a(ix): Non-Network Assets**Routine expenditure**

Project or programme*

IT software

(\$000)

(\$000)

1,837

Building upgrades

1,496

Vehicles

159

Other plant & equipment

156

* include additional rows if needed

All other projects or programmes - routine expenditure

Routine expenditure

3,648

Atypical expenditure

Project or programme*

(\$000)

(\$000)

* include additional rows if needed

All other projects or programmes - atypical expenditure

Atypical expenditure

-

Expenditure on non-network assets

3,648

Company Name **Counties Energy Limited**
 For Year Ended **31 March 2021**

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		
8	Service interruptions and emergencies	((\$000))	2,492
9	Vegetation management		1,874
10	Routine and corrective maintenance and inspection		1,564
11	Asset replacement and renewal		508
12	Network opex		6,438
13	System operations and network support		3,498
14	Business support		7,819
15	Non-network opex		11,317
16			
17	Operational expenditure		17,755
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		497
23	* Direct billing expenditure by suppliers that directly bill the majority of their consumers		

Company Name **Counties Energy Limited**
For Year Ended **31 March 2021**

SCHEDULE 7: COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE

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

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

sch ref

7	7(i): Revenue	Target (\$000) ¹	Actual (\$000)	% variance
8	Line charge revenue	50,454	50,681	0%

9	7(ii): Expenditure on Assets	Forecast (\$000) ²	Actual (\$000)	% variance
10	Consumer connection	9,500	10,241	8%
11	System growth	6,620	5,363	(19%)
12	Asset replacement and renewal	30,909	28,231	(9%)
13	Asset relocations	300	396	32%
14	Reliability, safety and environment:			
15	Quality of supply	350	96	(73%)
16	Legislative and regulatory	—	—	—
17	Other reliability, safety and environment	—	—	—
18	Total reliability, safety and environment	350	96	(73%)
19	Expenditure on network assets	47,679	44,327	(7%)
20	Expenditure on non-network assets	11,791	3,648	(69%)
21	Expenditure on assets	59,471	47,975	(19%)

22	7(iii): Operational Expenditure			
23	Service interruptions and emergencies	2,100	2,492	19%
24	Vegetation management	1,500	1,874	25%
25	Routine and corrective maintenance and inspection	1,550	1,564	1%
26	Asset replacement and renewal	1,130	508	(55%)
27	Network opex	6,280	6,438	3%
28	System operations and network support	3,104	3,498	13%
29	Business support	7,877	7,819	(1%)
30	Non-network opex	10,980	11,317	3%
31	Operational expenditure	17,260	17,755	3%

32	7(iv): Subcomponents of Expenditure on Assets (where known)			
33	Energy efficiency and demand side management, reduction of energy losses		—	—
34	Overhead to underground conversion	3,790	6,949	83%
35	Research and development		—	—

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	491	497	1%

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

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)

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 BDA in its pricing schedules. Information is also required on the number of CPE that are included in each consumer or outlier price category code, and the energy delivered to those CPE.

and 100%

8(i): Billed Quantities by Price Component

Category code	Consumer type or price component, consumer code(s)	Standard or non-standard consumer group (specify)	Average price of CPE in in district per year (cents)	
			Standard	Non-standard
Residential	Commercial	Standard	7.25	135.12
Residential	Commercial	Non-standard	20.15	186.34
Low-Mid Income	Commercial	Standard	55.15	95.15
Low-Mid Income	Commercial	Non-standard	105	135.12
Low-Mid Income	Commercial	Non-standard	105	135.12
Other Customer 1	Commercial	Standard	2	45.15
Other Customer 1	Commercial	Non-standard	2	45.15
Other Customer 2	Commercial	Standard	2	45.15
Other Customer 2	Commercial	Non-standard	2	45.15
Other Customer 3	Commercial	Standard	2	45.15
Other Customer 3	Commercial	Non-standard	2	45.15
All other uses for different consumer groups of price category code in district			45.15	135.12
Non-billed consumer totals			45.15	135.12
Total for all consumers			45.15	135.12

8(ii): Line Charge Revenue (\$000) by Price Component

Category code	Consumer type or price component, consumer code(s)	Standard or non-standard consumer group (specify)	Total line charge revenue in district year		Total line charge revenue in district year		Total line charge revenue in district year	
			Standard	Non-standard	Standard	Non-standard	Standard	Non-standard
Residential	Commercial	Standard	552.27	55.15	552.27	55.15	552.27	55.15
Residential	Commercial	Non-standard	552.27	55.15	552.27	55.15	552.27	55.15
Low-Mid Income	Commercial	Standard	55.15	55.15	55.15	55.15	55.15	55.15
Low-Mid Income	Commercial	Non-standard	55.15	55.15	55.15	55.15	55.15	55.15
Low-Mid Income	Commercial	Non-standard	55.15	55.15	55.15	55.15	55.15	55.15
Other Customer 1	Commercial	Standard	55.15	55.15	55.15	55.15	55.15	55.15
Other Customer 1	Commercial	Non-standard	55.15	55.15	55.15	55.15	55.15	55.15
Other Customer 2	Commercial	Standard	55.15	55.15	55.15	55.15	55.15	55.15
Other Customer 2	Commercial	Non-standard	55.15	55.15	55.15	55.15	55.15	55.15
Other Customer 3	Commercial	Standard	55.15	55.15	55.15	55.15	55.15	55.15
Other Customer 3	Commercial	Non-standard	55.15	55.15	55.15	55.15	55.15	55.15
All other uses for different consumer groups of price category code in district			552.27	55.15	552.27	55.15	552.27	55.15
Non-billed consumer totals			552.27	55.15	552.27	55.15	552.27	55.15
Total for all consumers			552.27	55.15	552.27	55.15	552.27	55.15

8(iii): Number of CPE directly billed

Number of directly billed CPE per year

Other

000

Billed quantities by price component

Price component

Units billed by the BDA (not of demand, but of capacity, use)

Category code	Consumer type or price component, consumer code(s)	Standard or non-standard consumer group (specify)	Day	Evening	Weekend	Off-peak	Peak	Priority	Emergency	Winter Peak	Winter Off-peak	Actual	Report	Standard	Supply	Transmission
Residential	Commercial	Standard	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12
Residential	Commercial	Non-standard	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12
Low-Mid Income	Commercial	Standard	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12
Low-Mid Income	Commercial	Non-standard	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12
Other Customer 1	Commercial	Standard	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12
Other Customer 1	Commercial	Non-standard	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12
Other Customer 2	Commercial	Standard	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12
Other Customer 2	Commercial	Non-standard	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12
Other Customer 3	Commercial	Standard	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12
Other Customer 3	Commercial	Non-standard	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12
All other uses for different consumer groups of price category code in district			135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12
Non-billed consumer totals			135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12
Total for all consumers			135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12

Line charge revenue (\$000) by price component

Price component

Units billed by the BDA (not of demand, but of capacity, use)

Category code	Consumer type or price component, consumer code(s)	Standard or non-standard consumer group (specify)	Day	Evening	Weekend	Off-peak	Peak	Priority	Emergency	Winter Peak	Winter Off-peak	Actual	Report	Standard	Supply	Transmission
Residential	Commercial	Standard	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12
Residential	Commercial	Non-standard	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12
Low-Mid Income	Commercial	Standard	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12
Low-Mid Income	Commercial	Non-standard	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12
Other Customer 1	Commercial	Standard	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12
Other Customer 1	Commercial	Non-standard	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12
Other Customer 2	Commercial	Standard	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12
Other Customer 2	Commercial	Non-standard	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12
Other Customer 3	Commercial	Standard	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12
Other Customer 3	Commercial	Non-standard	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12
All other uses for different consumer groups of price category code in district			135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12
Non-billed consumer totals			135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12
Total for all consumers			135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12	135.12

8(iii): Number of CPE directly billed

Number of directly billed CPE per year

Other

Company Name
For Year Ended

Counties Energy Limited
31 March 2021

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

					Items at start of	Items at end of		Data accuracy
	Voltage	Asset category	Asset class	Units	year (quantity)	year (quantity)	Net change	(1-4)
8	All	Overhead Line	Concrete poles / steel structure	No.	26,074	26,000	(74)	3
9	All	Overhead Line	Wood poles	No.	1,858	1,832	(26)	3
10	All	Overhead Line	Other pole types	No.	64	61	(3)	3
11	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	72	71	(1)	4
12	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	66	65	(1)	4
13	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	1	0	(1)	4
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	0	0	–	N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	0	0	–	N/A
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	0	0	–	N/A
17	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	0	0	–	N/A
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	0	0	–	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	0	0	–	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	0	0	–	N/A
21	HV	Subtransmission Cable	Subtransmission submarine cable	km	0	0	–	N/A
22	HV	Zone substation Buildings	Zone substations up to 66kV	No.	6	6	–	4
23	HV	Zone substation Buildings	Zone substations 110kV+	No.	3	4	1	4
24	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	0	0	–	N/A
25	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	14	19	5	4
26	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	0	0	–	4
27	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	31	31	–	4
28	HV	Zone substation switchgear	33kV RMU	No.	0	0	–	N/A
29	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	0	0	–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	12	12	–	4
31	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	79	93	14	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	0	0	–	N/A
33	HV	Zone Substation Transformer	Zone Substation Transformers	No.	15	17	2	4
34	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1,457	1,454	(3)	3
35	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	0	0	–	N/A
36	HV	Distribution Line	SWER conductor	km	0	0	–	N/A
37	HV	Distribution Cable	Distribution UG XLPE or PVC	km	202	242	40	3
38	HV	Distribution Cable	Distribution UG PILC	km	21	14	(7)	3
39	HV	Distribution Cable	Distribution Submarine Cable	km	2	2	–	4
40	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	40	41	1	3
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	0	0	–	N/A
42	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	5,061	5,042	(19)	3
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	0	0	–	N/A
44	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	278	318	40	3
45	HV	Distribution Transformer	Pole Mounted Transformer	No.	3,177	3,180	3	3
46	HV	Distribution Transformer	Ground Mounted Transformer	No.	917	951	34	3
47	HV	Distribution Transformer	Voltage regulators	No.	7	15	8	3
48	HV	Distribution Substations	Ground Mounted Substation Housing	No.	887	927	40	3
49	LV	LV Line	LV OH Conductor	km	723	713	(10)	3
50	LV	LV Cable	LV UG Cable	km	800	830	30	3
51	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	46	47	1	3
52	LV	Connections	OH/UG consumer service connections	No.	45,401	46,749	1,348	3
53	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	144	186	42	3
54	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	1	1	–	4
55	All	Capacitor Banks	Capacitors including controls	No.	19	38	19	3
56	All	Load Control	Centralised plant	Lot	5	6	1	4
57	All	Load Control	Relays	No.	3,469	3,217	(252)	3
58	All	Civils	Cable Tunnels	km	0	0	–	N/A
59								

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.

[illegible]

Company Name **Counties Energy Limited**For Year Ended **31 March 2021**

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)
11	> 66kV	66	0
12	50kV & 66kV		
13	33kV	72	2
14	SWER (all SWER voltages)		
15	22kV (other than SWER)	569	194
16	6.6kV to 11kV (inclusive—other than SWER)	886	91
17	Low voltage (< 1kV)	715	832
18	Total circuit length (for supply)	2,308	1,119
19			
20	Dedicated street lighting circuit length (km)	0	47
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)		2
22			
23	Overhead circuit length by terrain (at year end)	Circuit length (km)	(% of total overhead length)
24	Urban	182	8%
25	Rural	2,063	89%
26	Remote only		—
27	Rugged only	63	3%
28	Remote and rugged		—
29	Unallocated overhead lines		—
30	Total overhead length	2,308	100%
31			
32		Circuit length (km)	(% of total circuit length)
33	Length of circuit within 10km of coastline or geothermal areas (where known)	1,533	45%
34		Circuit length (km)	(% of total overhead length)
35	Overhead circuit requiring vegetation management	2,308	100%

Company Name

Counties Energy Limited

For Year Ended

31 March 2021

SCHEDULE 9d: REPORT ON EMBEDDED NETWORKS

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

sch ref

	Location *	Number of ICPs served	Line charge revenue (\$000)
8			
9	Counties 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 2021**

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

9e(i): Consumer Connections

Number of ICPs connected in year by consumer type

Consumer types defined by EDB*

Urban Residential
Urban Commercial
Rural Residential
Rural Commercial

* include additional rows if needed

Connections total

Number of
connections (ICPs)

463
344
270
262

1,339

Distributed generation

Number of connections made in year
Capacity of distributed generation installed in year

161 connections

1.39 MVA

9e(ii): System Demand**Maximum coincident system demand**

GXP demand
plus Distributed generation output at HV and above

Maximum coincident system demand

less Net transfers to (from) other EDBs at HV and above

Demand on system for supply to consumers' connection points

Demand at time
of maximum
coincident
demand (MW)

133
8
141
—
141

Electricity volumes carried

Electricity supplied from GXPs
less Electricity exports to GXPs
plus Electricity supplied from distributed generation
less Net electricity supplied to (from) other EDBs
Electricity entering system for supply to consumers' connection points

less Total energy delivered to ICPs

Electricity losses (loss ratio)

Energy (GWh)

620
—
52
—
672
636
37

5.4%

Load factor

0.54

9e(iii): Transformer Capacity

Distribution transformer capacity (EDB owned)
Distribution transformer capacity (Non-EDB owned, estimated)
Total distribution transformer capacity

Zone substation transformer capacity

(MVA)

481
64
546
473

Company Name **Counties Energy Limited**For Year Ended **31 March 2021**

Network / Sub-network Name

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

10(i): Interruptions**Interruptions by class**

Class A (planned interruptions by Transpower)
 Class B (planned interruptions on the network)
 Class C (unplanned interruptions on the network)
 Class D (unplanned interruptions by Transpower)
 Class E (unplanned interruptions of EDB owned generation)
 Class F (unplanned interruptions of generation owned by others)
 Class G (unplanned interruptions caused by another disclosing entity)
 Class H (planned interruptions caused by another disclosing entity)
 Class I (interruptions caused by parties not included above)

Total**Number of interruptions**

245
277
29
551

Interruption restoration

Class C interruptions restored within

≤3Hrs >3hrs

177	100
-----	-----

SAIFI and SAIDI by class

Class A (planned interruptions by Transpower)
 Class B (planned interruptions on the network)
 Class C (unplanned interruptions on the network)
 Class D (unplanned interruptions by Transpower)
 Class E (unplanned interruptions of EDB owned generation)
 Class F (unplanned interruptions of generation owned by others)
 Class G (unplanned interruptions caused by another disclosing entity)
 Class H (planned interruptions caused by another disclosing entity)
 Class I (interruptions caused by parties not included above)

Total**SAIFI SAIDI**

0.44	138.29
2.60	134.47
0.01	2.61
3.05	275.37

Normalised SAIFI and SAIDI

Classes B & C (interruptions on the network)

Normalised SAIFI Normalised SAIDI

3.04	271.37
------	--------

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

Lightning
 Vegetation
 Adverse weather
 Adverse environment
 Third party interference
 Wildlife
 Human error
 Defective equipment
 Cause unknown

SAIFI SAIDI

0.00	0.04
0.49	23.91
0.50	42.70
0.26	6.40
0.11	3.18
0.62	32.39
0.63	25.84

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

Subtransmission lines
 Subtransmission cables
 Subtransmission other
 Distribution lines (excluding LV)
 Distribution cables (excluding LV)
 Distribution other (excluding LV)

SAIFI SAIDI

0.00	0.0
0.00	0.0
0.00	0.0
0.34	105.1
0.10	33.2
0.00	0.0

Company Name **Counties Energy Limited**For Year Ended **31 March 2021**

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.

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

Subtransmission lines

Subtransmission cables

Subtransmission other

Distribution lines (excluding LV)

Distribution cables (excluding LV)

Distribution other (excluding LV)

SAIFI

SAIDI

0.03

0.86

0.20

3.97

1.80

106.64

0.31

18.42

0.26

4.59

10(v): Fault Rate**Main equipment involved**

Subtransmission lines

Subtransmission cables

Subtransmission other

Distribution lines (excluding LV)

Distribution cables (excluding LV)

Distribution other (excluding LV)

Total

Number of Faults

Circuit length (km)

8

138

2

2

2

1,455

262

8

5

285

285

Fault rate (faults
per 100km)

5.80

—

18.01

2.81

Company Name	Counties Energy Limited
For Year Ended	31 March 2021

Schedule 14 Mandatory Explanatory Notes

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

1. This schedule requires EDBs to provide explanatory notes to information provided in accordance with clauses 2.3.1, 2.4.21, 2.4.22, and subclauses 2.5.1(1)(f), and 2.5.2(1)(e).
2. This schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.1. Information provided in boxes 1 to 11 of this schedule is part of the audited disclosure information, and so is subject to the assurance requirements specified in section 2.8.
3. Schedule 15 (Voluntary Explanatory Notes to Schedules) provides for EDBs to give additional explanation of disclosed information should they elect to do so.

Return on Investment (Schedule 2)

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

Box 1: Explanatory comment on return on investment

Classification is consistent with previous treatment.

ROI comparable to a post tax WACC decreased from 5.88% in FY20 to 3.69% in FY21 with the following items of note:

- Gross Line Revenue (before posted discount) increased by 2.4% in FY21. Higher posted discounts of \$10.9m (FY20 - \$8.4m) reduced net revenue to \$50.7m (FY20 - \$51.7m);
- Operational costs increased from 30% of lines revenue in FY20 to 35% of lines revenue this year to address high network growth and targeted improvements in reliability and the customer experience; and
- Revaluations decreased from \$6.8m in FY20 to \$4.4m in FY21. This was attributable to lower CPI of 1.5% (FY20 – 2.5%).

Regulatory Profit (Schedule 3)

5. In the box below, comment on regulatory profit for the disclosure year as disclosed in Schedule 3. This comment must include-

- 5.1 a description of material items included in other regulated income (other than gains / (losses) on asset disposals), as disclosed in 3(i) of Schedule 3
- 5.2 information on reclassified items in accordance with subclause 2.7.1(2).

Box 2: Explanatory comment on regulatory profit

Line charge revenue and operational expenditure excludes non-regulated Smart Meters. Other regulated income includes only standard recoveries relating to the regulated business (eg electricity reserve market).

There were no changes in classification within regulatory profit this disclosure year.

Merger and acquisition expenses (3(iv) of Schedule 3)

6. If the EDB incurred merger and acquisitions expenditure during the disclosure year, provide the following information in the box below-
 - 6.1 information on reclassified items in accordance with subclause 2.7.1(2)
 - 6.2 any other commentary on the benefits of the merger and acquisition expenditure to the EDB.

Box 3: Explanatory comment on merger and acquisition expenditure

There were no mergers or acquisitions during the disclosure year.

Value of the Regulatory Asset Base (Schedule 4)

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

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

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

Assets being disposed of comprise non-system vehicles and minor plant and equipment (\$62k) and transformers sold as scrap (\$117k). A loss of \$87k was recorded for these disposals.

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

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 (\$24k), entertainment expense (\$13k) and other (\$17k).

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 (\$557k @28% = \$156k).

Cost allocation (Schedule 5d)

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

Box 7: Cost allocation

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

- Property identified space usage as the proxy allocator; and
- Finance, IT and Corporate costs allocated costs using resource as the proxy allocator.

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

Asset allocation (Schedule 5e)

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

Box 8: Commentary on asset allocation

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

In particular:

- Property identified space usage as the proxy allocator where costs could not be directly allocated; and
- Finance, IT and Corporate costs used resource as the proxy allocator.

No items have been reclassified during the disclosure year.

Capital Expenditure for the Disclosure Year (Schedule 6a)

12. In the box below, comment on expenditure on assets for the disclosure year, as disclosed in Schedule 6a. This comment must include-
- 12.1 a description of the materiality threshold applied to identify material projects and programmes described in Schedule 6a;
 - 12.2 information on reclassified items in accordance with subclause 2.7.1(2).

Box 9: Explanation of capital expenditure for the disclosure year

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

13.2: Classification is consistent with treatment in prior years.

Operational Expenditure for the Disclosure Year (Schedule 6b)

13. In the box below, comment on operational expenditure for the disclosure year, as disclosed in Schedule 6b. This comment must include-
- 13.1 Commentary on assets replaced or renewed with asset replacement and renewal operational expenditure, as reported in 6b(i) of Schedule 6b;
 - 13.2 Information on reclassified items in accordance with subclause 2.7.1(2);
 - 13.3 Commentary on any material atypical expenditure included in operational expenditure disclosed in Schedule 6b, including the value of the expenditure the purpose of the expenditure, and the operational expenditure categories the expenditure relates to.

Box 10: Explanation of operational expenditure for the disclosure year

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

Classification is consistent with previous treatment.

Variance between forecast and actual expenditure (Schedule 7)

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

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

7(i): Line charge revenue was in line with target.

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

- System growth was 19% below target due to land procurement for future substations being deferred into FY22. This was done to provide additional time for due diligence;
- Asset relocations were 32% above target but within \$100k due to more customer initiated applications than anticipated;
- Quality of supply was 73% below target and due to a low numbers of voltage complaints through the year.
- Expenditure on non-network assets was lower than forecast due to a delayed start for the Glasgow site upgrade.

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

- Service interruptions and emergencies were 19% higher than target but offset by lower asset replacement spend with some of that work undertaken while addressing interruptions (as opposed to a higher spend).
- Vegetation management was 25% above target with additional work carried out to improve network reliability. This remains an area of focus;
- Operational Asset replacement was 55% below target due to classification of service interruption costs as noted above. Overall, these two categories were \$230k lower than target with a higher level of capitalisation work undertaken in the year;
- Higher systems operations and network support is due to network growth that accelerated above budget levels in FY21. This is forecast to continue.

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

- Several projects were converted from overhead to underground where there were benefits, including reliability and safety, that outweighed the additional cost.

Information relating to revenues and quantities for the disclosure year

15. In the box below provide-

- 15.1 a comparison of the target revenue disclosed before the start of the disclosure year, in accordance with clause 2.4.1 and subclause 2.4.3(3) to total billed line charge revenue for the disclosure year, as disclosed in Schedule 8; and
- 15.2 explanatory comment on reasons for any material differences between target revenue and total billed line charge revenue.

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

Total billed line charge revenue was in line with the target of \$50.5m.

Network Reliability for the Disclosure Year (Schedule 10)

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

Box 13: Commentary on network reliability for the disclosure year

Both planned (class B) and unplanned (class C) outages, as measured by SAIDI, returned a satisfactory result for FY21. Total Normalised planned and unplanned SAIDI was 17% less than the result for FY20.

Results were also favourable to targets stated in our Asset Management Plan, which are based on the DPP (2015-2020) methodology.

For FY21, Counties Energy has reallocated SAIFI / SAIDI arising from events initiating from privately owned network assets to Class I although the impact is minor. 0.66 SAIDI / 0.002 SAIFI has been reallocated from Class C with the balance in Class I moving from Class B.

Consistent with prior years 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.

For consistency with our thresholds and prior years we have reported the information in Schedule 10 in line with our interpretation as outlined above, thus Counties Energy have accepted the "Successive Interruption" exemption. However, we have also recalculated SAIFI based on the alternative interpretation and note SAIFI for FY21 would increase by 9.18% from 3.05 to 3.33 and normalised planned and unplanned SAIFI by 9.21% from 3.04 to 3.32.

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	<u>Counties Energy Limited</u>
For Year Ended	<u>31 March 2021</u>

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	<u>Counties Energy Limited</u>
For Year Ended	<u>31 March 2021</u>

Schedule 15 Voluntary Explanatory Notes

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

1. This schedule enables EDBs to provide, should they wish to-
 - 1.1 additional explanatory comment to reports prepared in accordance with clauses 2.3.1, 2.4.21, 2.4.22, 2.5.1 and 2.5.2;
 - 1.2 information on any substantial changes to information disclosed in relation to a prior disclosure year, as a result of final wash-ups.
2. Information in this schedule is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.
3. Provide additional explanatory comment in the box below.

Box 1: Voluntary explanatory comment on disclosed information

On 10 August 2021, Counties Energy Limited changed its name from Counties Power Limited. The legal entity is unchanged and there has been no change to ownership or management.

Consistent with prior years 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.

For consistency with our thresholds and prior years we have reported the information in Schedule 10 in line with our interpretation as outlined above, thus Counties Energy have accepted the “Successive Interruption” exemption. However, we have also recalculated SAIFI based on the alternative interpretation and note SAIFI for FY21 would increase by 9.18% from 3.05 to 3.33 and normalised planned and unplanned SAIFI by 9.21% from 3.04 to 3.32.



Schedule 18 Certification for Year-end Disclosures

Clause 2.9.2

We, Vern Dark and Hamish Stevens, being directors of Counties Energy Limited (formerly Counties Power Limited) certify that, having made all reasonable enquiry, to the best of our knowledge -

- a) the information prepared for the purposes of clauses 2.3.1, 2.3.2, 2.4.21, 2.4.22, 2.5.1, 2.5.2, and 2.7.1 of the Electricity Distribution Information Disclosure Determination 2012⁽¹⁾ in all material respects complies with that determination;
- b) the historical information used in the preparation of Schedules 8, 9a, 9b, 9c, 9d, 9e, 10, and 14 has been properly extracted from Counties 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.

A handwritten signature in black ink, appearing to be "Vern Dark", written over a horizontal line.

Vern Dark
25 August 2021

A handwritten signature in black ink, appearing to be "Hamish Stevens", written over a horizontal line.

Hamish Stevens
25 August 2021

(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 (FORMERLY COUNTIES POWER LIMITED) AND TO THE COMMERCE COMMISSION ON THE DISCLOSURE INFORMATION FOR THE DISCLOSURE YEAR ENDED 31 MARCH 2021 AS REQUIRED BY THE ELECTRICITY DISTRIBUTION INFORMATION DISCLOSURE DETERMINATION 2012

Counties Energy Limited (formerly Counties Power Limited) (the Company) is required to disclose certain information under the Electricity Distribution Information Disclosure Determination 2012 (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, Mark Bramley, 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 2021 (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 (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 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.

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, in all material respects, 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 (NZ) 3100 (Revised) requires that we comply with the International Standard on Assurance Engagements (New Zealand) 3000 (Revised) *Assurance Engagements Other Than Audits or Reviews of Historical Financial Information*.

We have obtained sufficient recorded evidence and explanations that we required to provide a basis for our 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 Input Methodologies, are similar to those used in the measurement of fixed assets in the financial statements, however, there are a number of different requirements and complexities which require careful consideration. Due to the importance of the RAB within the regulatory regime, the incentives to overstate the RAB value, and complexities within the regulations, we have considered it to be a key assurance matter.	We have obtained an understanding of the compliance requirements relevant to the RAB as set out in the Determination and the IM Determination. We have performed the following procedures. Assets commissioned • We reconciled the assets commissioned, as per the regulatory fixed asset register, to the asset additions disclosed in the audited annual financial statements and investigated any reconciling items. • We inspected the assets commissioned during the period, as per the regulatory fixed asset register, to identify any specific cost or asset type exclusions, as set out in the 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 verified the spreadsheet formula utilised to calculate <i>regulatory depreciation expense is in line with IM Determination clause 2.2.5.</i> 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.

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



Directors' responsibilities

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

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

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

Auditor's responsibilities

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

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

To meet these responsibilities, we planned and performed procedures in accordance with SAE (NZ) 3100 (Revised), to obtain reasonable assurance about whether the Company has complied, in all material respects, with the Disclosure Information (which includes the Related Party Transaction Information) required to be audited by the Determination.

An assurance engagement to report on the Company's compliance with the Determination involves performing procedures to obtain evidence about the compliance activity and controls implemented to meet the requirements. The procedures selected depend on our judgement, including the identification and assessment of the risks of material non-compliance with the requirements.

Inherent limitations

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

Restricted use

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



Independence and quality control

We complied with the Auditor-General's:

- independence and other ethical requirements, which incorporate the independence and ethical requirements of Professional and Ethical Standard 1 issued by the New Zealand Auditing and Assurance Standards Board; and
- quality control requirements, which incorporate the quality control requirements of Professional and Ethical Standard 3 (Amended) issued by the New Zealand Auditing and Assurance Standards Board.

The Auditor-General, and his employees, and PricewaterhouseCoopers and its partners and employees, may deal with the Company on normal terms within the ordinary course of trading activities of the Company. Other than any dealings on normal terms within the ordinary course of trading activities of the Company, this engagement, and the annual audit of the Company's financial statements, we have no relationship with or interests in the Company.

A handwritten signature in black ink, reading 'Mark Bramley'.

Mark Bramley
On behalf of the Auditor-General
Auckland, New Zealand
25 August 2021

A handwritten signature in black ink, reading 'PricewaterhouseCoopers'.

PricewaterhouseCoopers